

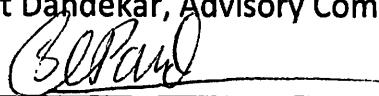
**ECONOMIC ASSESSMENT OF ALASKA NORTH SLOPE HYDRATE-BEARING
RESERVOIR REGIONAL PRODUCTION DEVELOPMENT SCHEMES**

By

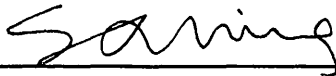
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Spring 2015

To: Grad school 4/21/15

**ECONOMIC ASSESSMENT OF ALASKA NORTH SLOPE HYDRATE-BEARING
RESERVOIR REGIONAL PRODUCTION DEVELOPMENT SCHEMES**

A PROJECT

Presented to the Faculty

of the University of Alaska Fairbanks

in Partial Fulfillment of the Requirements

for the Degree of

MASTER OF SCIENCE

By

Stephanie P. Nollner, M.Chem

Fairbanks, Alaska

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ABSTRACT

The objective of this project was to evaluate the economic feasibility of producing the upper C sand of the Prudhoe Bay Unit L Pad gas-hydrate-bearing reservoir. The analysis is based on numerical modelling of production through depressurization completed in CMG STARS by a fellow UAF graduate student, Jennifer Blake, (2015). A staged field development plan was proposed, and the associated capital and operating costs were estimated using Siemens's Oil and Gas Manager planning software and costing database. An economic assessment was completed, incorporating the most common royalties, the current taxes laws applicable to conventional gas development, and most recent tariff estimates.

The degree of vertical heterogeneity, initial average hydrate saturation, well spacing and well type had a significant impact on the regional gas production profiles in terms of cumulative volume produced, and more importantly, the expediency of gas production. The volume that is economically recoverable is highly dependent on how the field is developed. A field that has higher vertical heterogeneity and corresponding lower average initial hydrate saturation is most economically produced using horizontal wells at 160 acre spacing; the acceleration of gas production outweighs the increased drilling costs associated with the longer wells and tighter well spacing. The choice of development scenario does not impact the project economics significantly given a field that has lower vertical heterogeneity; however, development using horizontal wells at 320 acre spacing is marginally more economic than the alternatives. Assuming a Minimum Attractive Rate of Return of 20%, the minimum gas price that would allow economic production of ANS gas hydrates was found to be \$29.83 per million British thermal units; this value is contingent on the reservoir having high average initial hydrate saturation and being developed with horizontal wells at 320 acre spacing. A slightly higher gas price of \$36.18 per million British thermal units would allow economic production of a reservoir having low average initial hydrate saturation that is developed with horizontal wells at 160 acre spacing.

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DISCLAIMER

The data, analysis, conclusions, opinions and interpretations presented in this project do not represent the opinions, views or position of BP, as operator, or the Working Interest Owners, of Prudhoe Bay.

INTRODUCTION

1.1 Objective

In order to become worthy of attention by oil and gas developers, methane hydrate accumulations must be shown to be both technically and economically feasible to produce. A number of short-term production test wells drilled on the Alaska North Slope (ANS) in recent years have successfully shown that hydrates can be produced to the surface, and they have highlighted specific considerations that must be taken into account when designing production wells. The objective of this project is to evaluate the economic feasibility of producing the ANS hydrate accumulations.

Both conventional and unconventional ANS gas is currently stranded in place, with no path to market. However, the economic environment is beginning to shift. Two projects are actively exploring opportunities to develop natural gas processing facilities and a natural gas pipeline to deliver ANS gas to the marketplace: the Alaska Stand Alone Pipeline (ASAP) and the Alaska Liquefied Natural Gas (AK LNG) project. The AK LNG project gained momentum in early 2014, being endorsed through a Heads of Agreement signed by the State of Alaska, the Alaska Gasline Development Corporation (AGDC), TransCanada Alaska Development Inc., ExxonMobil Alaska Production Inc., ConocoPhillips Alaska Inc. (CPAI), and BP Exploration (Alaska) Inc. (BPXA). The unprecedented alignment between both the land owners and industry has led to the enactment of legislation tailored for gas production and sales. With a potential path to market for ANS gas on the horizon, the economic feasibility of methane hydrate production becomes even more interesting than it was in the past.

Numerical reservoir simulations based on these test wells have been developed and used by a fellow UAF graduate student, Jennifer Blake, to generate 50-year production profiles for the upper C sands of the Eileen formation (Blake, 2015). A number of sensitivities were run to evaluate the impact of both reservoir description

uncertainty and well completion design and spacing. Both the test well and numerical simulations will be discussed in detail in the appropriate sections of this report.

A regional development scheme will be developed as part of this study. Typical field development timing, outlined by Scott Wilson in his ANS regional gas hydrate modeling forecasts (2011), will be applied, and the individual well forecasts will be summed to create a field-wide production forecast. The infrastructure required for production, separation and treatment of the produced fluids will be reviewed in light of the flow assurance threats that such a field would face. Capital and operating expenditure will be estimated using Oil and Gas Manager by Siemens and fed into an economic model that incorporates typical royalties and the current state and federal tax laws.

Depressurization is the only production technique that will be evaluated in this study; however, further synergies between hydrate production and commercialization may exist. In order for the conventional gas resources to be sold, all acid gases (carbon dioxide and hydrogen sulfide) must be removed. The carbon dioxide stream that will be generated may have potential for use in hydrate production. This has been shown to be technically feasible in the short-term injection/production test at the Ignik Sikumi well (Schoderbek, 2013). However, this production method will not be evaluated as part of this study because long term reservoir modelling for a carbon dioxide/methane exchange development scheme is not yet available. Development of a model that can address the kinetic processes associated with hydrates, 1) hydrate formation, 2) hydrate dissociation, and 3) guest molecule exchange, is currently underway at the Pacific Northwest National Laboratory (PNNL) (White, 2014). Long term well performance data should be available in the latter half of 2015.

1.2 Introduction to Hydrates

Hydrates are solid crystalline inclusion compounds consisting of a lattice of hydrogen-bonded water encasing small gas molecules. Various gases can form

hydrate compounds; however, methane is the most common gas molecule found in natural gas hydrates. Naturally formed hydrates typically take one of two structures: Structure I or Structure II (Figure 1). Both structures contain a water cavity with twelve faces and five sides per face. The difference between the structures is how the water cavities are linked together. In Structure I, the vertices of the cavities are linked, forming a body-centered cubic structure. This structure is formed with smaller gas molecules, namely methane, carbon dioxide, and hydrogen sulfide. In Structure II, the faces of the cavities are linked, forming a diamond lattice within a cubic framework. This structure accommodates larger gas molecules, such as propane and iso-butane. For a thorough yet concise review of gas hydrates, the reader is referred to (Koh, 2002).

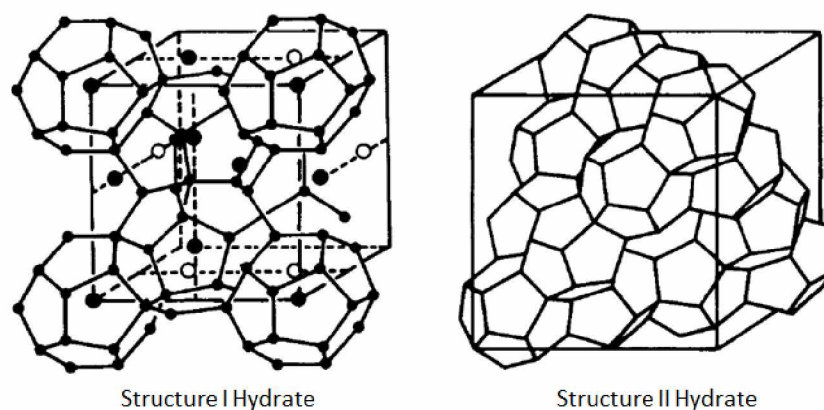


Figure 1 Hydrate Structure I and II
(Sloan, 1991)

Hydrates are formed, and remain stable, under low temperature and high pressure conditions (Figure 2). When the temperature is increased and/or the pressure is reduced sufficiently, gas hydrates will dissociate into liquid water and gas. When dissociation occurs, the liberated gas occupies a significantly larger volume than the gas hydrate. One unit volume of gas hydrate may contain as much as 180 unit volumes of gas at standard conditions (Sloan, 1991). Before being considered a

natural gas resource, hydrates were simply viewed as a shallow drilling hazard for wells accessing deeper oil-bearing formations.

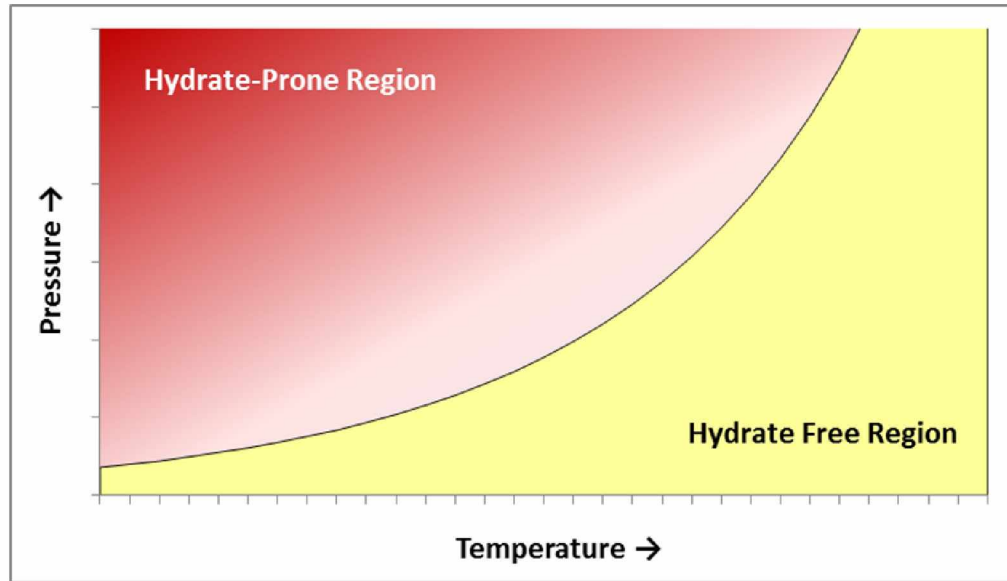


Figure 2 Hydrate Dissociation Curve

1.2.1 Geographic Distribution of Hydrates

Naturally occurring gas hydrate accumulations are found worldwide; however, because of the conditions required for stability, namely low temperatures and high pressures, they are restricted to polar and oceanic regions (Kvenvolden, 1993). Global hydrate reserves are estimated to be 100,000 to 3×10^8 trillion cubic feet (TCF) (Collett, 2001). The hydrate resource pyramid shown in Figure 3 captures the major types of deposits in which hydrates can be found and places them roughly in the order that they are most likely to be developed. The vast majority of methane hydrates are found in low permeability marine sediments that are unlikely to become a target for commercial production. Offshore hydrates in marine sands, and possibly in fractured non-sand marine sediments (e.g. silts and clays), are considered the major target for long term development of gas hydrates as a resource (Ruppel, 2011).

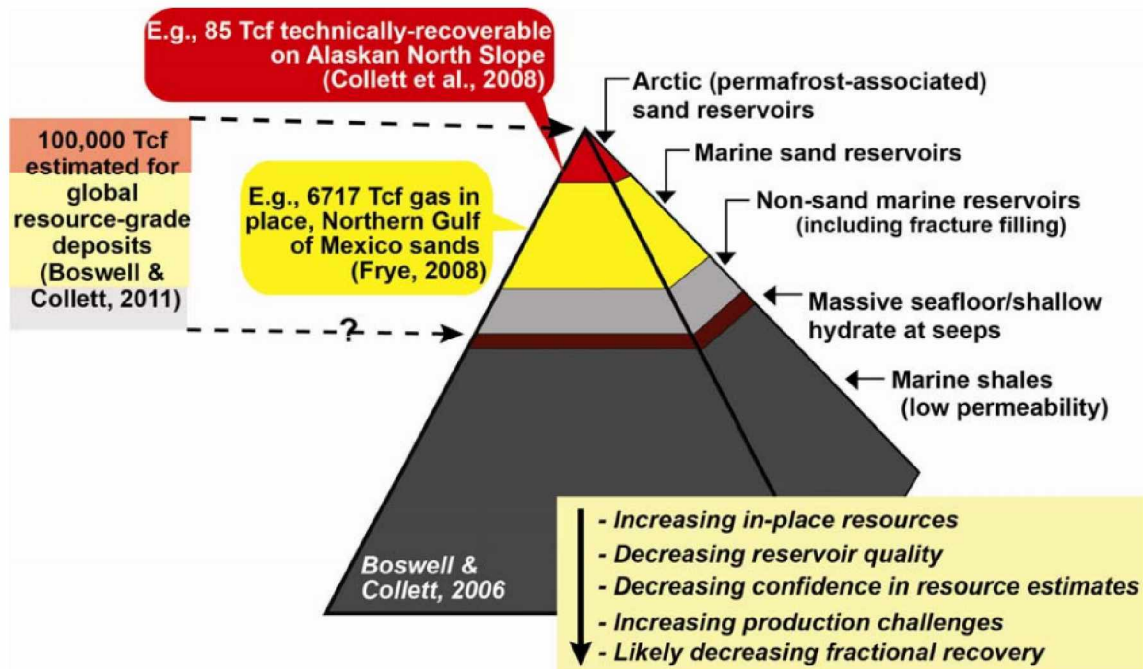
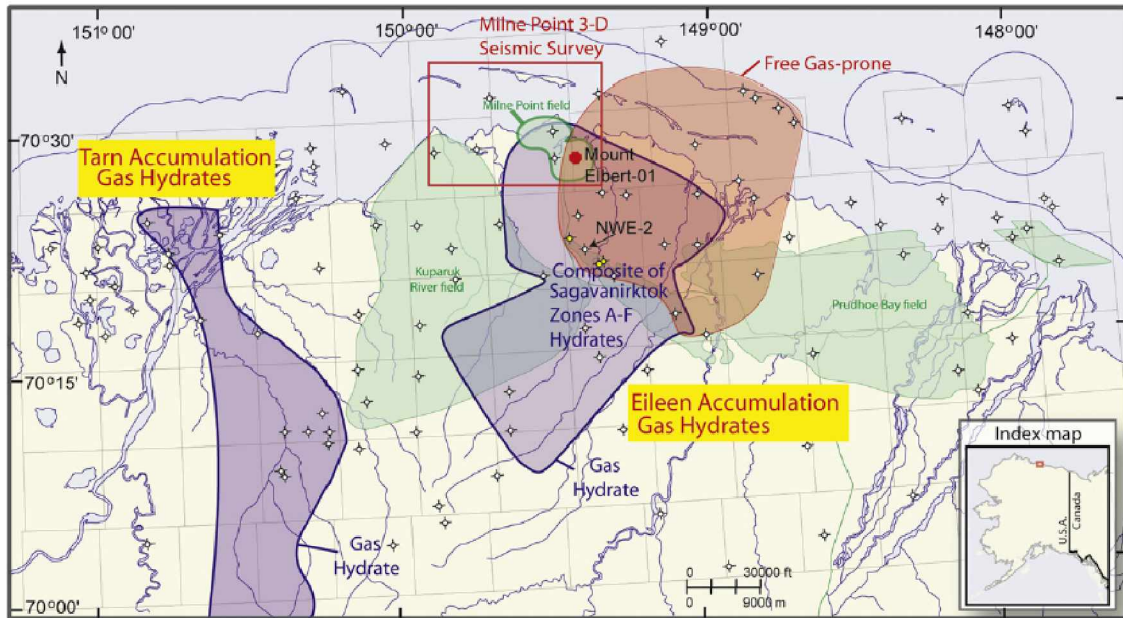


Figure 3 Hydrate Resource Pyramid
(Ruppel, 2011 - modified from Boswell and Collett, 2006)

High permeability sediments in permafrost areas have been placed at the top of the pyramid. While the volume of gas in place is relatively small compared to that found in marine environments, it is more easily accessed and has a higher probability of being commercialized first (Ruppel, 2011). United States Geological Survey (USGS) estimated that the ANS gas hydrates within and beneath the permafrost may contain up to 590 TCF (Collett, 1995). The "Eileen" and "Tarn" gas hydrate accumulations are estimated to contain 100 TCF of gas in place; these formations are of particular interest because they are in close proximity to established ANS oil and gas production infrastructure (Figure 4), namely the Prudhoe Bay Unit (PBU), Kuparuk River Unit (KRU) and Milne Point Unit (MPU) (Collett, 1993). The Eileen accumulation was further assessed to contain over 33 TCF of gas in place (Collett, 1995). These volumes present a significant prize if they can be shown to be both technically and economically feasible to produce.



**Figure 4 Major Gas Hydrate Accumulations on the Alaska North Slope
(Hunter et al., 2011)**

1.2.2 Formation of Hydrate Accumulations

Hydrate accumulations require the same components of a conventional petroleum system. In addition to the correct pressure and temperature stability conditions, there must be a gas source, which is typically thermogenic in nature, gas migration, and a suitable reservoir with a trap (Collett, 2011). While the formation processes are not well understood, the most commonly discussed mechanisms are 1) formation as methane exsolves from water due to changes in water-solubility as methane-saturated water migrates upward through sediment columns (Hyndman and Davis, 1992), 2) advection of bubble-phase methane into the gas hydrate stability zone along preferential permeability pathways (Milkov and Sassen, 2002), and 3) conversion of free gas accumulations to gas hydrate by late-stage imposition of gas hydrate stability conditions (Collett, 1993, 2002).

The Mount Elbert Hydrate Stratigraphic Test Well was planned as part of the cooperative research and development effort between the Department of Energy's

National Energy Technology Laboratory (NETL), BPXA, and the USGS with the goal of improving the understanding of the nature and occurrence of ANS gas hydrates. The well was successfully drilled, logged, cored and pressure tested from a temporary ice pad within MPU in 2007. According to an analysis of the log and core data by Boswell et al., several aspects of the ANS gas hydrate accumulation support the assertion that it was formed by conversion of free-gas by late-stage imposition of gas hydrate stability conditions: firstly, the gas hydrates show no preference for accumulation near the base of the hydrate stability zone despite the presence of high-quality reservoirs; secondly, gas hydrates are restricted to the upper part of the sand units in which they are found despite the fact that these are sometimes the lower-quality section of the reservoirs; thirdly, the reservoir sands are often only partially filled, with sharp basal contacts (Boswell, 2011).

1.2.3 Classification of Hydrate Accumulation

Natural gas hydrate accumulations are divided into four main classes (Figure 5). The classification is based on the geometry of the unit and the nature of the upper and lower reservoir boundaries. Class 1 deposits comprise a hydrate layer positioned over a two-phase fluid zone containing mobile gas and water. Class 2 deposits comprise a hydrate layer positioned over a mobile water zone. Class 3 deposits are single hydrate layers without any underlying mobile fluids. Class 4 deposits are found in low saturations on the seafloor (Moridis and Sloan, 2007; Moridis and Collett, 2004).

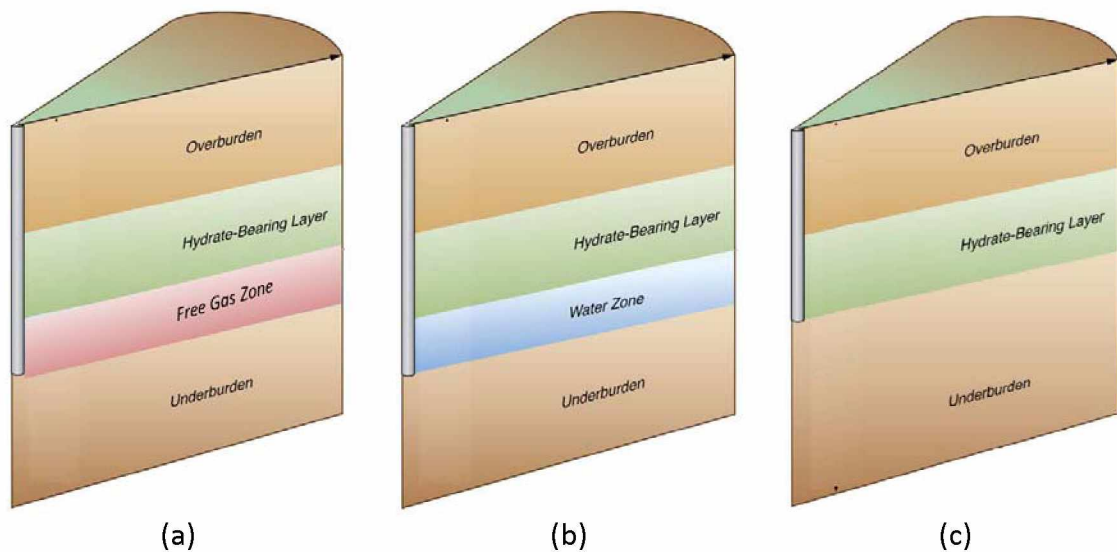
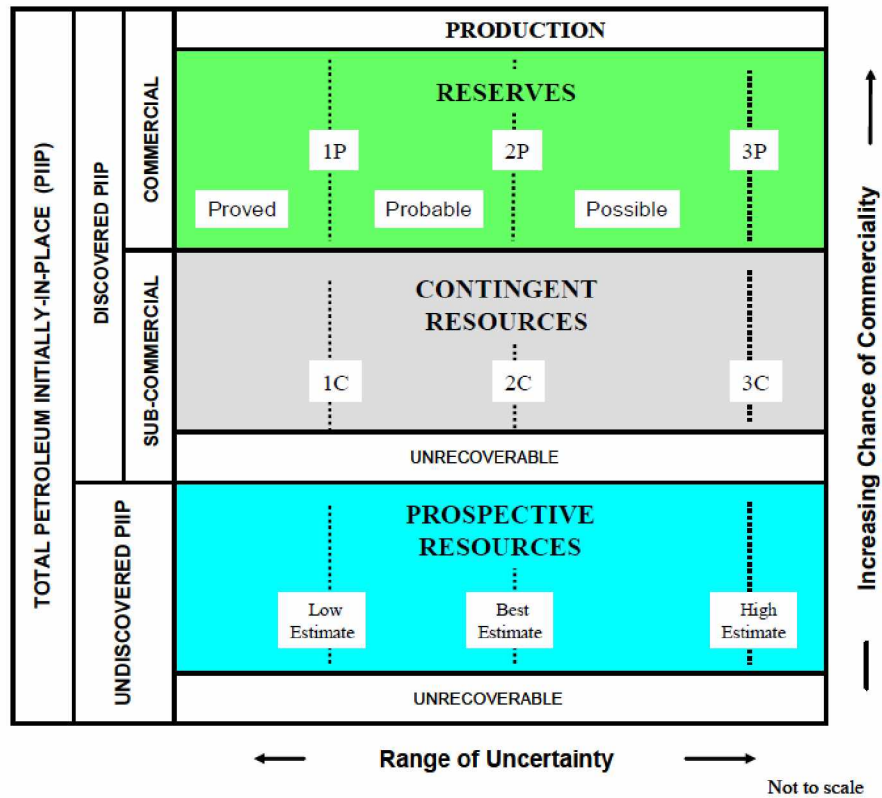


Figure 5 Gas Hydrate Reservoir Classes
(a) Class 1, (b) Class 2, (c) Class 3
(after Moridis, 2012)

The estimation of petroleum resource quantities involves inherent degree of uncertainty. The Petroleum Resources Management System (PRMS) was developed in sponsorship by the Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC) and Society of Petroleum Evaluation Engineers (SPEE) in an attempt to standardize the approach to estimating petroleum quantities, evaluating development projects and presenting results within a comprehensive classification framework. A graphical illustration of this framework is provided in Figure 6; the horizontal axis represents the “range of uncertainty” represents the range of estimated quantities potentially recoverable from an accumulation by a project, and the vertical axis represents the “chance of commerciality”.



**Figure 6 Resources Classification Framework
(SPE, 2007)**

The ANS gas hydrate accumulations are classified as unconventional, contingent resources. Contingent resources are discovered resources that are considered “potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development”; this may be due to either technological or business hurdles (SPE, 2007). The term “reserves” is limited to petroleum resources which are commercially recoverable and have been justified for development. In order to promote hydrates into the reserves category, a project must be defined, there must be evidence of firm intention by a company’s management to proceed with development within a reasonable time frame and all required internal and external approvals should be in place (SPE, 2007). In other words, the key uncertainties that prevented commercial development must be clarified and removed.

1.2.4 Hydrate Production Technology

The natural gas held within hydrates can be produced if the hydrates can be made to dissociate. Hydrates can be destabilized in a number of ways: 1) increasing the temperature, 2) reducing the pressure, 3) adding a chemical inhibitor and 4) facilitating an exchange with an alternative gas molecule (Figure 7).

Depressurization is the least energy intensive option (Burshears et al., 1986; Moridis and Collett, 2003). In order to produce gas at commercially viable rates the dissociation area needs to be large. Historically, gas hydrate accumulations have been thought of as effectively impermeable (Howe, 2004), which would significantly hinder the propagation of a pressure front. However, recent studies have confirmed injectivity into naturally occurring methane hydrates on the ANS (Schoderbek et al., 2013). Production by depressurization is of particular interest in hydrate accumulations that overlie a free gas reservoir. The reservoir pressure can be quickly depleted by producing the free gas, which will in turn destabilize the hydrate at the hydrate-free gas interface.

Carbon dioxide hydrates are thermodynamically more stable than methane hydrates (Seo et al., 2013). The concept of exchanging methane for carbon dioxide in natural gas hydrates has been a subject of study for years (Hirohaman et al., 1996; Lee et al., 2003). This concept presents an attractive method of both producing methane from gas hydrates while also effectively sequestering carbon dioxide, a known greenhouse gas. Technical feasibility issues associated with this type of production were explored in laboratory experiments: injection of carbon dioxide into a hydrate-bearing system in the presence of excess water will result in a reduction in permeability, but the permeability will not be reduced to zero; delivery of carbon dioxide via a carbon dioxide/nitrogen mixture yielded a more efficient carbon dioxide/methane exchange than injection of liquid carbon dioxide; core flood evaluations suggested the formation was unlikely to fail during a carbon dioxide/methane exchange (Stevens et al., 2008; Graue et al., 2006). The production

method was proved to be technically feasible in the Ignik Sikumi Hydrate Well drilled in 2012 (Schoderbek et al., 2013); this is discussed in greater detail in section 2.2.4.

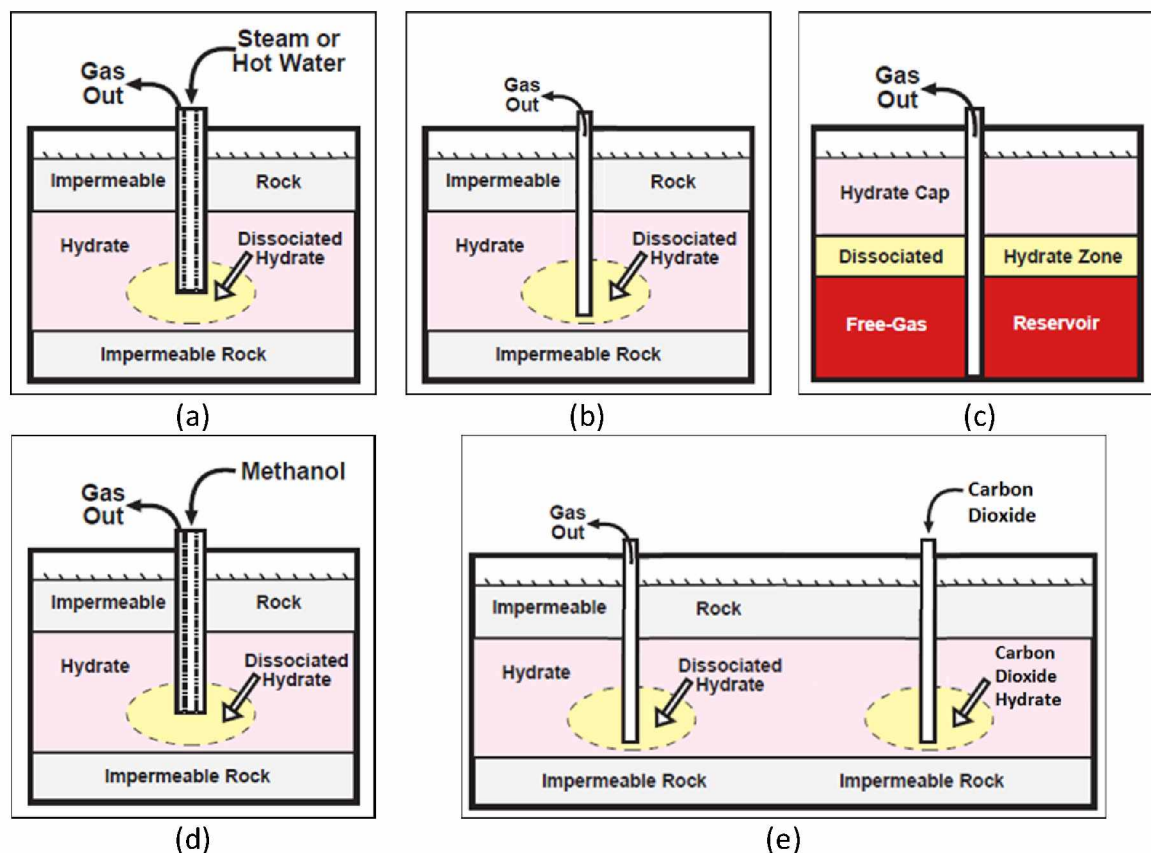


Figure 7 Schematic of Proposed Gas Hydrate Production Methods

(a) thermal injection, (b) depressurization of hydrate reservoir, (c) depressurization of free gas reservoir below hydrates, (d) inhibitor injection, (e) alternative gas molecule exchange (adapted from Collett, 2002)

Production of hydrocarbons using thermal means has some precedence, primarily in the techniques developed to exploit heavy oils, such as steam and hot water injection. While adaptation of these techniques for hydrate recovery has been suggested (McGuire, 1982; Bayles et. al, 1986), these techniques will be highly energy intensive given the fact that the vast majority of hydrate accumulations are offshore and in arctic regions. The additional complication of thermal stimulation is the large volume of water production that would accompany the gas, which would have to be

handled and disposed (Moridis et al., 2003). Likewise, the use of chemical inhibitors would be highly cost prohibitive.

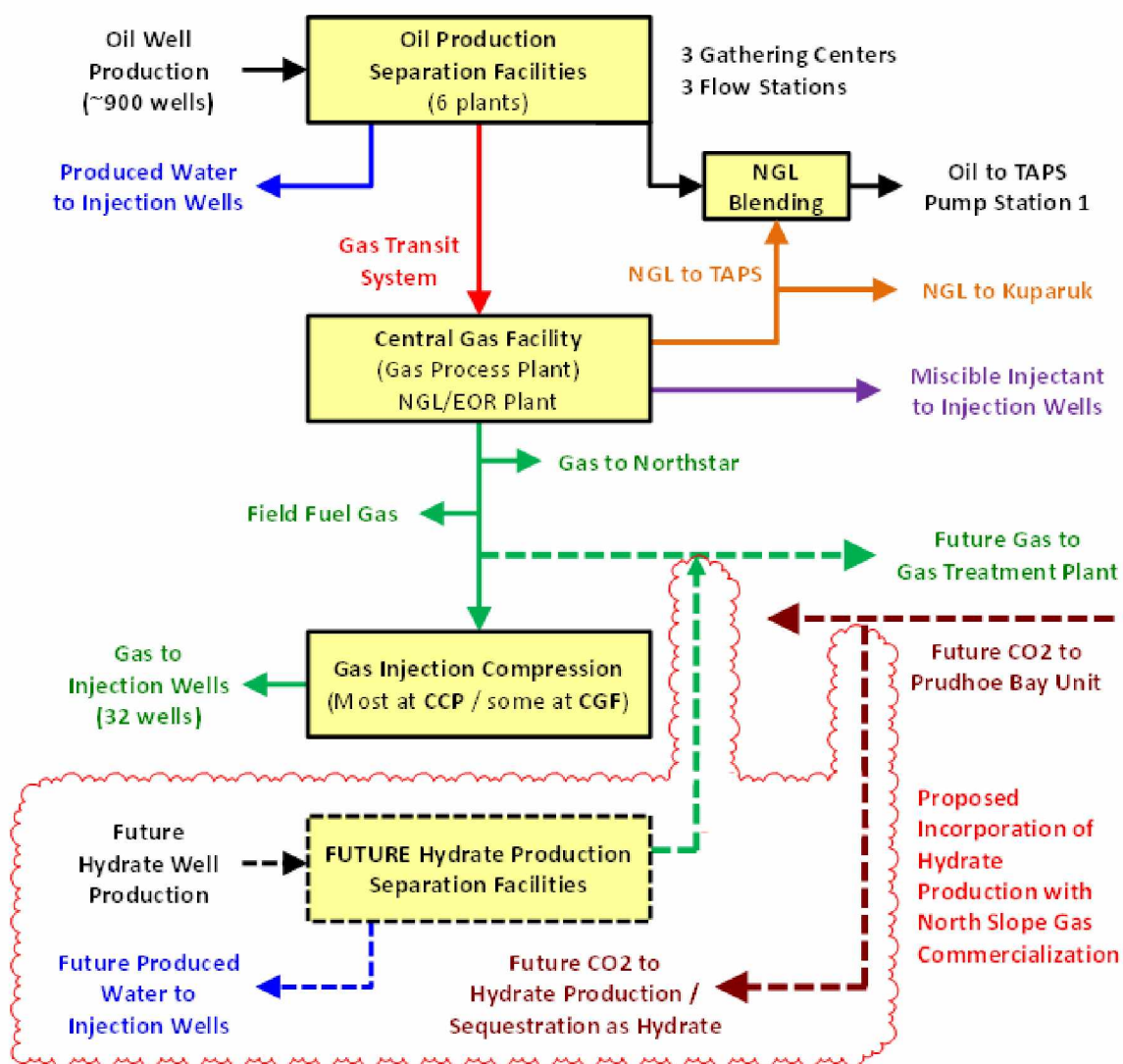
1.3 Alaska North Slope Gas Commercialization

Natural gas is a clean fuel and is among those giving the least pollution following combustion. It makes up a growing share of the world's energy supply. Energy demand is expected to rise by 1.5% a year through 2040, but gas demand is expected to grow faster at 1.7%; (IEA, 2014). Numerous projects have been sponsored over the years to evaluate the commercialization and export of ANS gas to outside markets, such as North America, Asia or both (Schulman, 2013). Two natural gas pipeline projects are actively being worked in Alaska: AK LNG and ASAP. Both projects are being progressed in parallel; however, only one will ultimately be built.

1.3.1 Alaska Liquefied Natural Gas Project

The AGDC, BP Alaska LNG LLC, ConocoPhillips Alaska LNG Company, ExxonMobil Alaska LNG LLC, and TransCanada Alaska Midstream LP plan to pursue one integrated LNG project to commercialize the conventional ANS gas resources (AK LNG HOA, 2014). The AK LNG project will include the engineering, design, construction and operation of interdependent facilities that will treat, transport, and liquefy a large volume of natural gas. The majority of the gas will be delivered to Nikiski for export to Asian markets; offtake points will be included to facilitate in-state use. Natural gas will be purchased from both PBU and Point Thomson Unit (PTU). Pipelines will be built to transport the gas from these units to a new Gas Treatment Plant (GTP), which will be fitted with three gas processing trains (Figure 8). The primary purpose is to remove the acid gases (carbon dioxide and hydrogen sulfide), dehydrate the sales gas and carbon dioxide streams, and cool and compress the sales gas using propane refrigeration. The GTP average annual capacity is expected to be up to 3.4 billion standard cubic feet per day (BCFD) of treated gas (3.7 BCFD at peak flow); this will

cogenerate a carbon dioxide stream at ~480 thousand standard cubic feet per day (MCFD) (AK LNG, 2014).



**Figure 8 AK LNG Gas Commercialization Block Flow Diagram
(modified from LNG Legislative Briefing Presentation, 2014)**

An 800-mile-long, 42-inch-diameter gas pipeline, with multiple gas off-takes for domestic gas, will transport the gas to a new LNG Plant in the Cook Inlet. There the gas will undergo a dehydration and mercury removal pretreatment process. It will

then be liquefied in one of the three modularized ~6 million tonne per annum (MTA) LNG trains (17-18 MTA total), generating ~1 thousand barrels per day (MBD) stabilized condensate (AK LNG, 2014). The LNG will be stored in one of three 160,000 cubic meter storage tanks prior to transfer to a new marine offloading facility.

1.3.2 Alaska Stand Alone Pipeline Project

The AGDC issued a Plan of Development for the ASAP project in June 2014. According to the design at the time, the ASAP project would deliver ANS gas resources to in-state markets. The project is described as follows in the Plan of Development (2014): a Gas Conditioning Facility (GCF), located near PBU, would remove the acid gases, dehydrate, compress and cool the gas for transportation to market. Initial gas production through the GCF would be less than 250 million standard cubic feet per day (MMCFD), with a peak capacity of 500 MMCFD. A 727-mile-long, 36-inch-diameter pipeline that would connect the GCF to the existing ENSTAR pipeline system in the Matanuska-Susitna Borough; Fairbanks will be supplied via a 29-mile-long, 12-inch-diameter lateral pipeline off the main transmission line. The capacity of the lateral pipeline to Fairbanks would be 60 MMCFD.

Governor Bill Walker has recently expressed his expectation that the scope of the ASAP project be modified. According to an article Gov. Walker wrote for the Juneau Empire, the original small-volume design of the ASAP project was necessary due to conditions under the Alaska Gasline Inducement Act (AGIA); with AGIA having been terminated in 2014, the project may be upsized to allow for both in-state gas sales and export to outside markets (Walker, 2015).

CHAPTER 2 LITERATURE REVIEW

2.1 Offshore Hydrate Stratigraphic Testing

2.1.1 Nankai Trough Gas Hydrate Test Wells

The Japan Oil, Gas, and Metals National Corporation (JOGMEC), with funding from the Ministry of Economic Trade and Industry, conducted the first offshore methane hydrate production test in March 2013. The test site was located on the margin of the Daini Atsumi Knoll, off the coasts of Atsumi and Shima peninsulas, in the eastern Nankai Trough, Japan. Methane rich sedimentary layers were identified through seismic studies and well data collected from 2001 through 2008. Field work comprised drilling three wells: one production well and two monitoring wells. The reserves were produced via depressurization during a test that spanned six days; a cumulative volume of 4.2 MMCF of gas was produced, averaging 700 thousand cubic feet per day (MCFD). The test was terminated after an increase in sand production occurred (JOGMEC, 2013).

2.1.2 Ulleung Basin Gas Hydrate Test Wells

South Korea has a strong national gas-hydrate program led by the Korean Gas Hydrate Research and Development Organization, Korean National Oil Corporation, Korea Institutes of Geoscience and Mineral Resources, Korean Gas Corporation, etc. Two large scale gas hydrate exploration and drilling expeditions have been made in the East Sea. The first, the Ulleung Basin Gas Hydrate Expedition 1, was completed in 2007. The first leg included drilling five logging-while-drilling wells used to characterize the geologic conditions in the basin; the findings were used to select a subset of three sites that were most likely to contain gas hydrates. The second leg included drilling and coring operations, and gas hydrates were recovered at all three sites (Park et al., 2008). The second expedition, Ulleung Basin Gas Hydrate Drilling

Expedition, spanned from 2009 into 2010. The first phase included logging-while-drilling and measurements-while-drilling operations in 13 wells. Sediment cores were collected from 18 wells. The data collection process included wireline logging and vertical seismic profiling. The hydrates that were recovered occurred either filling pores within discrete turbidite sand layers or filling fractures within muddy sediments (Ryu, 2013).

2.2 Onshore Hydrate Stratigraphic Testing

2.2.1 Northwest Eileen State-2 Test Well

The first ANS dedicated gas hydrate exploration and test well, Northwest Eileen State-2, was drilled in PBU by ARCO and Exxon in 1972. The primary objective of the test was to evaluate oil reserves, but a secondary objective was to enable initial estimates of the gas hydrate reserves. The test data indicated limited gas production with a calculated maximum rate of only 3,960 standard cubic feet per day (CFD); the magnitude of the hydrate deposit was estimated at around 16 trillion cubic meters (Collett, 1993). Hydrates garnered little attention in the following years and were simply considered shallow drilling hazards.

2.2.2 Mallik Test Well

High concentrations of gas hydrates have been well documented in the Mackenzie Delta region of Canada's Northwest Territories with estimates of 3.7 TCF of gas in place. The original discovery well was drilled in 1971/72. A production research well program, sponsored by the Geological Survey of Canada, JOGMEC, GeoForschungsZentrum Potsdam, the USGS, the U.S. Department of Energy (DOE) and the Gas Authority of India Ltd/Oil and Natural Gas Corporation Ltd., started in December 2001 and continued through to March 2002; three wells were drilled, one hydrate production research well and two nearby scientific observation wells (Dallimore and Collett, 2005). The objective was to collect reservoir data, through logging and core

collection, and undertake production via both depressurization and thermal stimulation. The tests were successful in demonstrating production through depressurization only and depressurization following fracturing operations. Thermal stimulation resulted in continuous gas production at varying rates, reaching a maximum rate of 53 MCFD.

2.2.3 Mount Elbert Test Well

The Mount Elbert Hydrate well, sponsored by the Department of Energy (DOE) and BPXA in collaboration with the USGS, was successfully drilled in 2007. The objective was to collect a full suite of wireline log, core, and formation pressure test data with the goal of reducing uncertainty of key gas hydrate-bearing reservoir properties necessary for numerical simulations. The test was extremely successful in demonstrating that gas hydrate scientific research programs can be conducted within ANS infrastructure. The data collected, which includes wireline logs, formation test data, and data obtained from the core samples, has been used to derive reservoir properties such as intrinsic permeability, effective permeability, porosity, hydrate saturation, lithology, and more (Hunter et al., 2011).

2.2.4 Ignik Sikumi Test Well

The Ignik Sikumi Hydrate well, was sponsored by ConocoPhillips, the DOE and Japan Oil, Gas and Metals National Corporation (JOGMEC). The primary objective was to evaluate the carbon dioxide/methane exchange mechanism, a concept advanced by lab work at the University of Bergen (Stevens et al., 2008; Graue et al., 2006), in a short-term field trial; the secondary objective was to evaluate production by depressurization. The well was successfully drilled and logged in 2011; perforations in the Sagavanirktok Upper C sand, followed by exchange and depressurization tests, occurred in 2012 (Schoderbek, 2013).

The exchange test comprised injecting a 23 mol% carbon dioxide/nitrogen mixture for two weeks; shutting in the well for five days; and unassisted flowback followed by jet pumping above, near, and below the hydrate-stability pressure. The

downhole pressure, cumulative gas and cumulative water production are shown in Figure 9. In addition to water production, significant sand production was observed during all production phases except for the last.

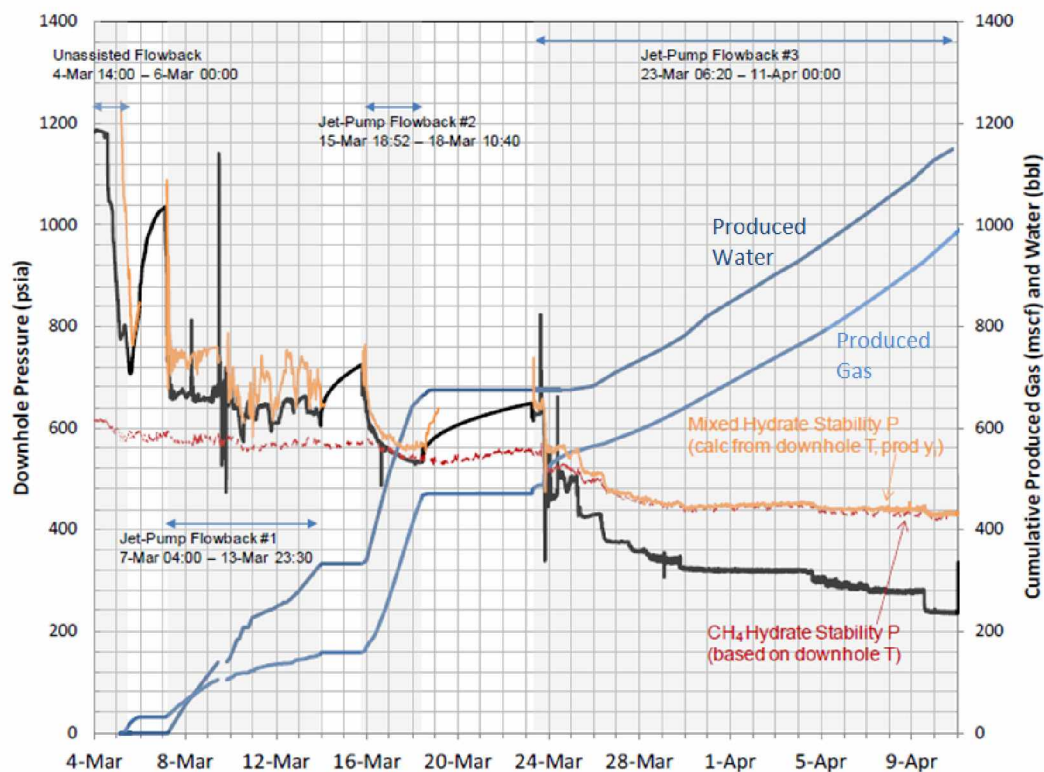


Figure 9 Ignik Sikumi Downhole Pressure, Cumulative Water and Gas Production (after Schoderbek, 2013)

The produced gas stream composition was monitored using an online gas chromatograph; the produced volumes were calculated and corrected to account the gas dissolved in the produced water stream (Figure 10) - carbon dioxide is more soluble in water than nitrogen or methane (Schoderbek, 2013). At the conclusion of the production test, 70% of the injected nitrogen was recovered, 40% of the injected carbon dioxide was recovered and 855 MCF of methane was produced (Schoderbek, 2013).

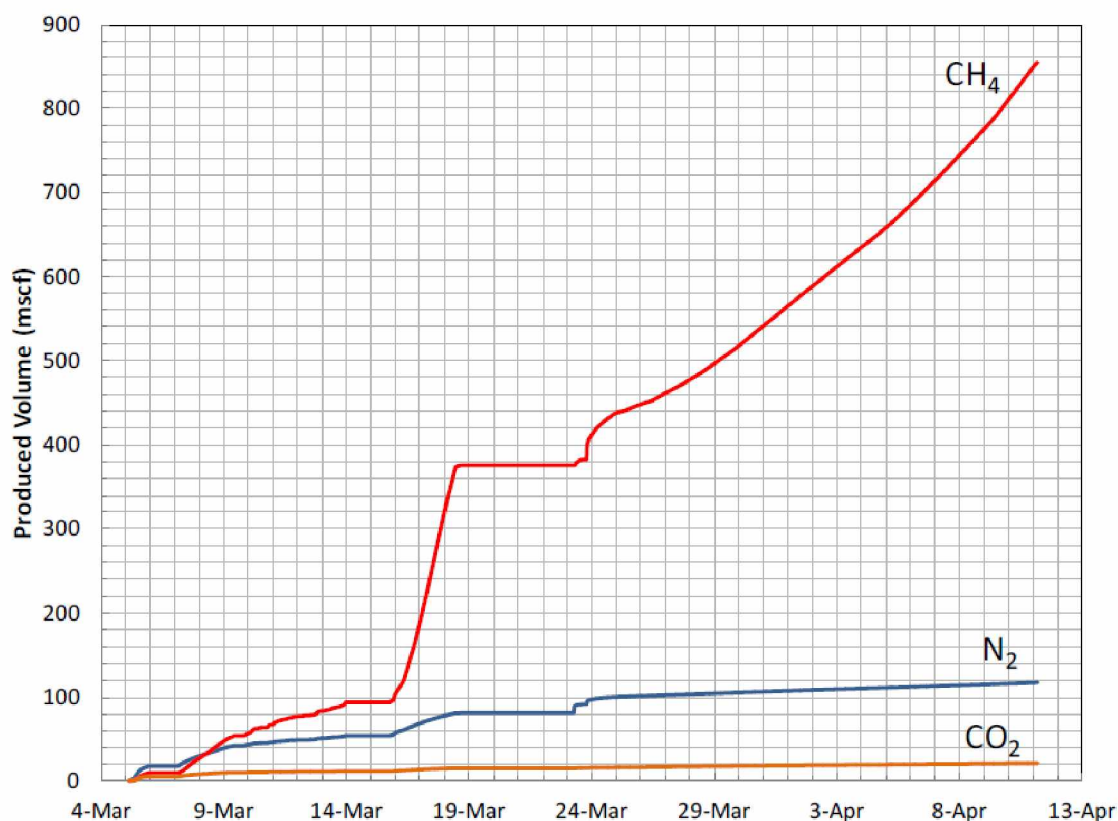


Figure 10 Ignik Sikumi Cumulative Methane, Nitrogen and Carbon Dioxide Production (Schoderbek, 2013)

The trial confirmed the following: a 23 mol% carbon dioxide/nitrogen mixture injected into a hydrate-bearing zone with free water will interact with the native hydrate; carbon dioxide/methane guest molecule exchange will occur; simple adiabatic homogeneous instantaneous equilibrium models cannot predict the observed production behavior; bottomhole pressures lower than the minimums at which equilibrium models predict ice will form are achievable (Schoderbek, 2013). A detailed account of the test design, monitoring data and results can be found in the ConocoPhillips Gas Hydrate Production Test Final Technical Report by Schoderbek et al. (2013) and in the Review of the Findings of the Ignik Sikumi CO₂-CH₄ Gas Hydrate Exchange Field Trial presented at the International Conference on Gas Hydrates by Anderson et al. (2014).

A numerical simulator, STOMP-HYDT-KE, was recently developed by the PNNL to better simulate the complex exchange mechanisms taking place in this type of production scheme; it is a member of the STOMP suite of numerical simulators, and is able to account for the formation of ternary hydrates and three different kinetic exchange processes: hydrate formation, hydrate dissociation and guest-molecule exchange (White, 2014). Ternary hydrates are hydrates with variable compositions of three guest molecules (CH₄, CO₂ and N₂). The simulator allows the hydrate and mobile phases to be in a non-equilibrium state and the guest molecule exchange to be kinetically controlled. The first simulations run with the model focused on applying kinetic exchange parameters measured during laboratory-scale experiments to simulations of the injection phase of the field trial (White, 2014). Further modelling, with the goal of generating long-term methane production and carbon dioxide sequestration profiles, will be conducted at the PNNL; this work is being funded by the DOE's NETL, and results may be available in the latter half of 2015.

2.3 Estimation of Recoverable Resources from the Eileen Accumulation

As stated earlier, the Eileen accumulation was assessed, through volumetric and probabilistic means, to contain over 33 TCF of gas in place (Collett, 1995). In order to generate interest from industry, a range of estimated ultimate recoveries (EURs) were calculated by Wilson et. al. (2011) by coupling reservoir modelling, based on the 2002 Mallik production tests, with a number of regional development scenarios.

The gas hydrate-bearing layers, assumed to include all the Eileen sand layers, were assumed to coexist with a slightly pressure conductive free-water lattice, i.e. mobile free water capable of providing a means of propagating a pressure front into the formation. Relative gas and water permeability in the presence of hydrates was estimated based upon the Code Comparison group and the Canadian Mallik hydrate research well; a value of 0.2 mD was used.

Type wells were created and tested at various intrinsic permeabilities, initial water saturations and relative permeabilities. The type-well volumes were assumed to be additive at the proposed 640 and 160 acre well spacing. The regional production model was built by proposing a typical resource development process: a long-term (2-year) single well pilot test is followed by a multi-well pilot test, limited initial development, full scale development, resource harvesting and optimization, resource management and infrastructure optimization, and eventually re-development given technology enabling advances. The reference case was based on positive, but not remarkable, single-well pilot test results. An upside case was based on a very positive response that would lead to pressure dissociation and development would progress at a rapid pace. The hypothetical development scenarios indicated that between 0 and 12 TCF may be technically recoverable from the 33 TCF of gas in place.

CHAPTER 3 PRODUCTION & ECONOMIC ANALYSIS METHODOLOGY

3.1 Resource Description

Collet et al. (2011) describe the Eileen formation as five laterally continuous gas-hydrate-bearing sand units, named A through E, that occur within the gas hydrate stability zone (Figure 11); note that the F sands remain above the base of the ice-bearing permafrost (BIBPF) zone.

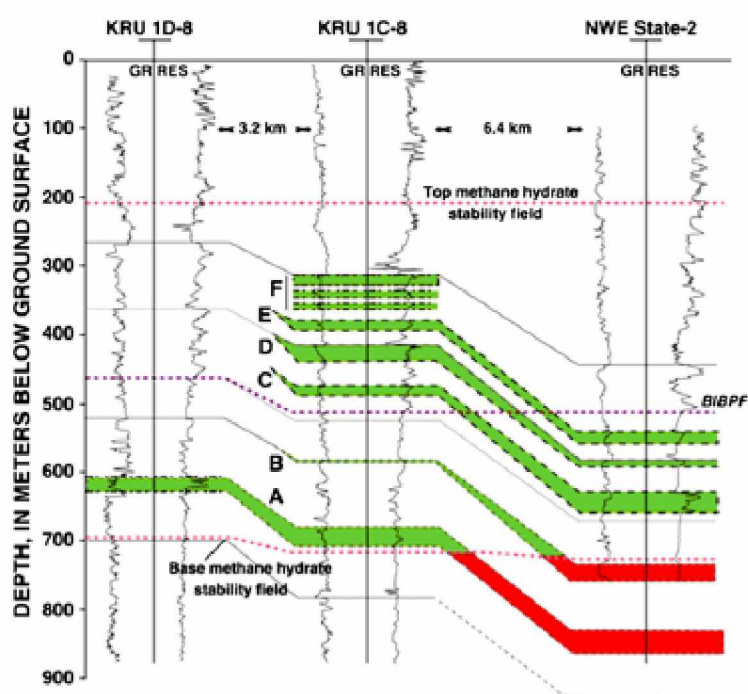


Figure 11 Gas Hydrate Zone Designations
(Wilson et al., 2011)

The C sand is composed of two sands, the upper C and lower C sands, which are separated by a shale layer. The Ignik Sikumi wireline data (Figure 12), the upper C hydrate-bearing sands are thicker and higher quality than the lower C sands (Schoderbek et al., 2013). The upper C sand was the focus of the reservoir modelling conducted by Blake (2015).

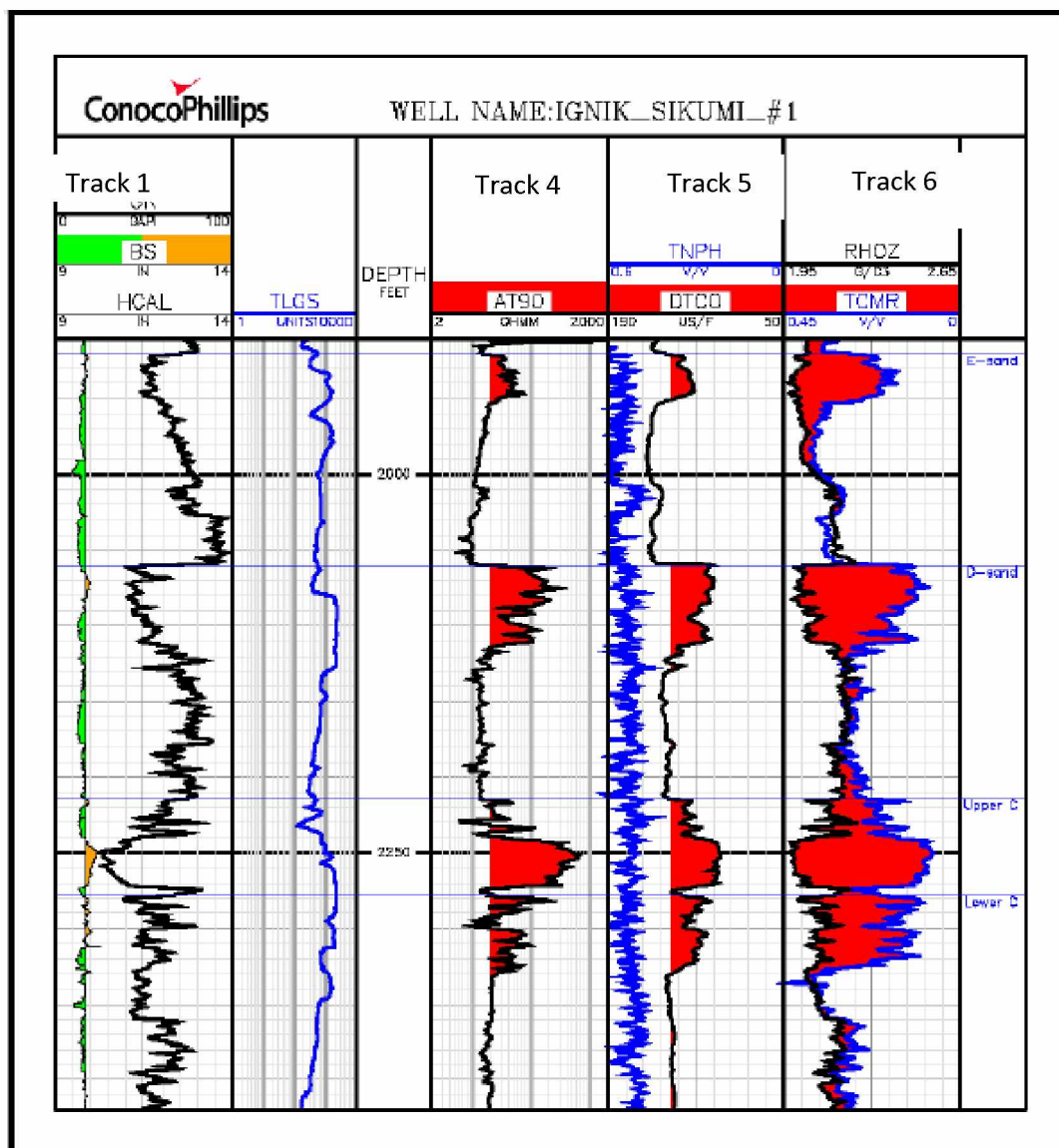


Figure 12 Ignik Sikumi Wireline Log Responses with Hydrate-Bearing Intervals Shaded (Schoderbeck et al., 2013).

3.2 Type Well Development

A numerical model was built for the upper C sand in the PBU L Pad hydrate-bearing reservoir to generate long-term production profiles; this work was completed by a fellow graduate student, Jennifer Blake (2015). Sensitivities were run to evaluate the impact of 1) fluid flow model, 2) average initial hydrate saturation and

corresponding vertical heterogeneity, 3) well completion type (vertical vs. horizontal) and 4) drainage area (320 acre vs. 160 acre). Gas and water production was modelled over a 50 year time period, targeting a flowing bottomhole pressure of 390 psi (2.7 MPa).

The fluid flow model was varied by running the model with two different relative permeability curves, one published by Kurihara (Kurihara et al., 2011) and one by Anderson (Blake, 2015). The results from both models were reviewed; the differences between the two were found to be insignificant in comparison to the mass balance errors of the model. Therefore, only production forecasts based on the Kurihara model were used in this study.

Two different scenarios were run to evaluate the impact of the vertical heterogeneity and corresponding average initial hydrate saturation of the upper C sand. The two models differ in the treatment of the reservoir layers near the upper and lower shale boundaries; according to the gamma ray log in Figure 12, these layers contain poorer quality sands with lower hydrate saturations. One model assumes that the hydrate saturation distribution is initially low in the layers near the upper and lower bounding shale layers and high in the center of the Class 3 hydrate-bearing sand; this is taken as representative of a reservoir with higher vertical heterogeneity and a lower average hydrate saturation of 51%. The other model assumes that the top eight meters of poor-quality sands near the upper shale layer are part of the impermeable shale region; this is taken as representative of a reservoir with lower vertical heterogeneity and higher average hydrate saturation of 75%.

Two different drainage areas, 320 acre well spacing and 160 acre well spacing, and well completion types, horizontal and vertical, were evaluated. Horizontal wells were placed in the first hydrate-bearing layer in the upper C sand in the center of the drainage area. Vertical wells placed in the center of the drainage area, and are perforated in every hydrate-bearing layer. The two different drainage areas under evaluation are conservative. In order to put these values in perspective, the Eagle

Ford shale gas play in Texas are being developed using 40 acre well spacing (Hiller, 2013).

3.2.1 Type Well Productivity

Six different type well production profiles were evaluated in this study. Cases A, B and C model the performance of a reservoir with a higher degree of vertical heterogeneity and a lower average initial hydrate saturation of 51%. Cases D, E and F model the performance of a reservoir with a lower degree of vertical heterogeneity and a higher average initial hydrate saturation of 75%. Cases A and D model horizontal well performance at 320 acre spacing, and Cases B, C, E and F model well both horizontal and vertical well performance at 160 acre spacing. The basis for each case, along with the peak production rate, cumulative production at 50 years, and overall methane recovery factors, are summarized in Table 1. The daily production rates and cumulative production rates over a 50 year life are provided for each case in Figure 13 through Figure 18 (Blake, 2015).

Reservoirs with a higher degree of heterogeneity and lower average initial hydrate saturation feature higher peak production rates, and higher overall methane recovery factors. This may be counterintuitive, but Blake provided a clear explanation: Reservoirs with a low initial hydrate saturation in a highly heterogeneous reservoir have high initial effective permeability to water; this, along with a high intrinsic permeability, results in the ability to efficiently propagate the pressure front and create the necessary pressure drop required to quickly produce the gas hydrates in the well drainage area. The pressure drop in these layers, which were filled with water initially, aides the dissociation of hydrates in the adjacent layers of comparatively high initial hydrate saturation. This leads to earlier peak production times, higher peak production rates and longer, flatter production tails (Blake, 2015). On the other hand, reservoirs with a lower degree of heterogeneity and higher average initial hydrate saturation are characterized by production rates that peak lower and later.

| Case Name | Average S_{hi} | Well Type & Spacing | Peak Gas Rate, MCFD | Time to Peak Gas, years | Cum. Gas at 50 years, BCF | Recovery Factor, % |
|--------------------|---------------------|-----------------------|------------------------|----------------------------|------------------------------|-----------------------|
| Case A (9) | 51% | Horizontal, 320 acres | 1,022 | 0 (14 days) | 6.2 | 42.3% |
| Case B (4) | 51% | Horizontal, 160 acres | 1,102 | 0.25 | 4.4 | 51.0% |
| Case C (1) | 51% | Vertical, 160 acres | 588 | 2 | 4.6 | 54.0% |
| Case D (17) | 75% | Horizontal, 320 acres | 3,864 | 11.5 | 6.0 | 25.5% |
| Case E (13) | 75% | Horizontal, 160 acres | 5,289 | 6 | 3.6 | 26.5% |
| Case F (11) | 75% | Vertical, 160 acres | 1,463 | 7.5 | 3.8 | 27.6% |
| Case (7) | 51% | Vertical, 320 acres | 587 | 3.5 | 5.9 | 40.3% |
| Case (15) | 75% | Vertical, 320 acres | 1,204 | 14.5 | 5.4 | 23.1% |

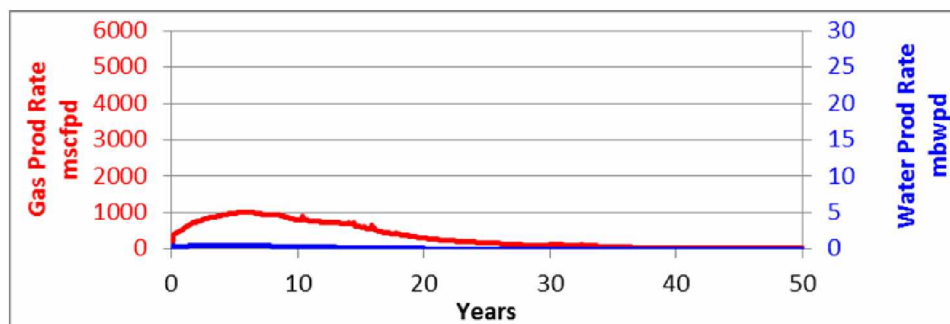
Table 1 Case Summaries from Blake (2015).

Note: Numbers in parentheses refer to case study numbers of Blake (2015).

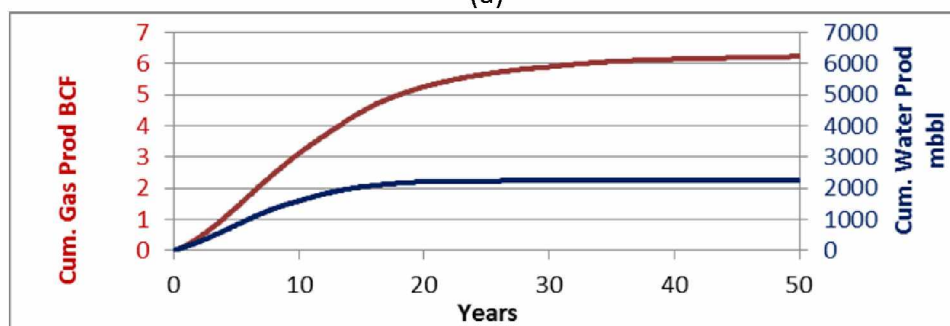
Horizontal wells significantly outperformed vertical wells at 320 acre spacing in terms of both peak and cumulative gas production (compare Cases 7 and 9 and Cases 15 and 17 in Blake, 2015); as a result, only horizontal wells are evaluated at 320 acre spacing in this economic evaluation. At 160 acre spacing the cumulative gas production from horizontal and vertical wells are very similar for either reservoir type; however, the horizontal well reaches a higher peak production in a shorter amount of time (compare Figure 14 to Figure 15 and Figure 17 to Figure 18), which is preferable from a time value of money standpoint - money earned today is worth more than money earned tomorrow. The value of accelerated production may outweigh the added cost of drilling horizontal wells. A more detailed account of the model results and conclusions drawn can be found in Blake's report (Blake, 2015).

3.2.2 Type Well Details

The target depth for hydrate formations, approximately 2300 feet, is extremely shallow when compared to conventional oil reservoirs. This will limit the maximum horizontal step-out for hydrate producing wells. While the C sand resides underneath pre-existing oil and gas infrastructure, new drill sites will need to be built in order to fully develop the resource; this will be discussed in further detail in Section 3.3. The following assumptions have been made to facilitate a first pass at the economics: the number of wells that can be drilled from one drillsite is limited to nine at 320 acre spacing and eighteen at 160 acre spacing, the average well length for a vertical well is 4260 feet, and the average length for a horizontal well is 6517 feet. Attempts were made in the estimation of the average well length to account for appropriate well spacing and horizontal step-out; however, a more rigorous analysis, taking into account reservoir development and drilling best practices could be completed as part of future work. Well bore design considerations will be discussed in Section 3.5.

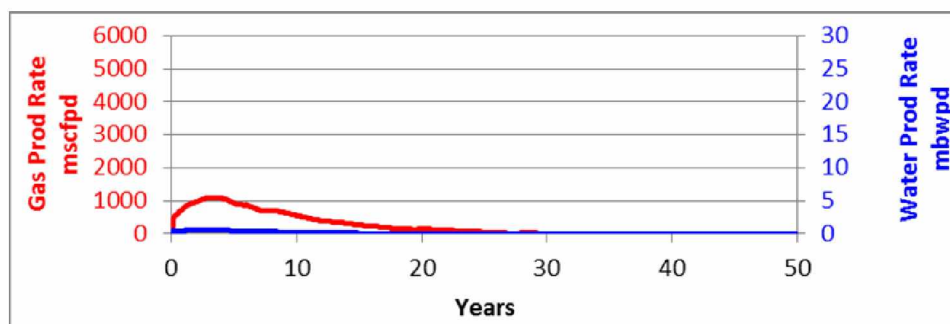


(a)

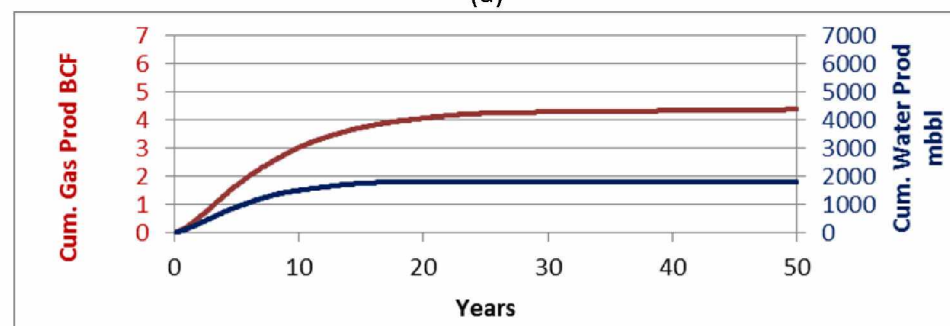


(b)

Figure 13 Case A well production rates (a) and cumulative production (b).
 [320 acre spacing, horizontal completion, 51% average initial hydrate saturation]

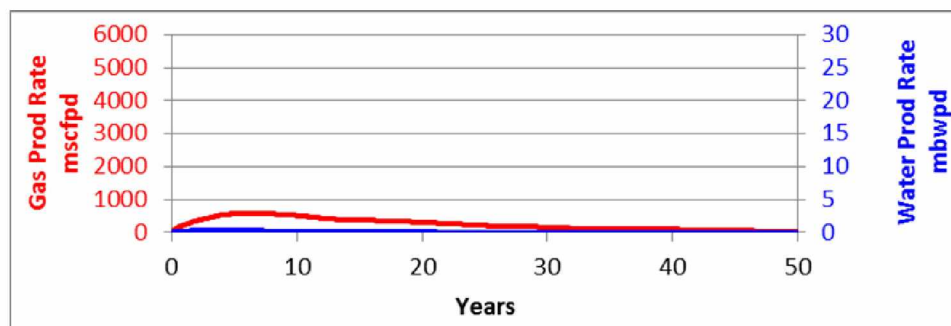


(a)

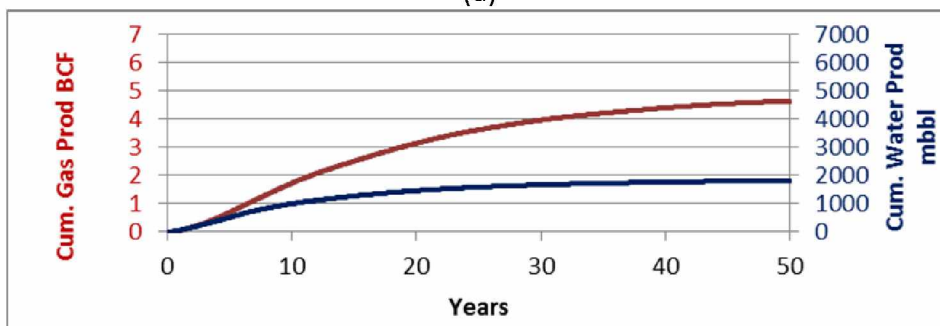


(b)

Figure 14 Case B well production rates (a) and cumulative production (b).
 [160 acre spacing, horizontal completion, 51% average initial hydrate saturation]

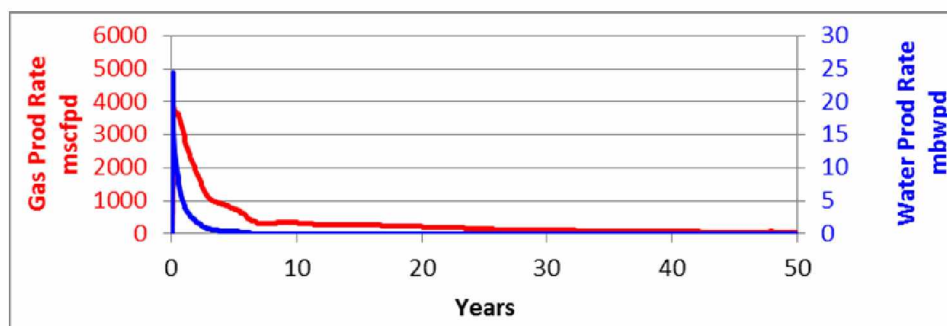


(a)

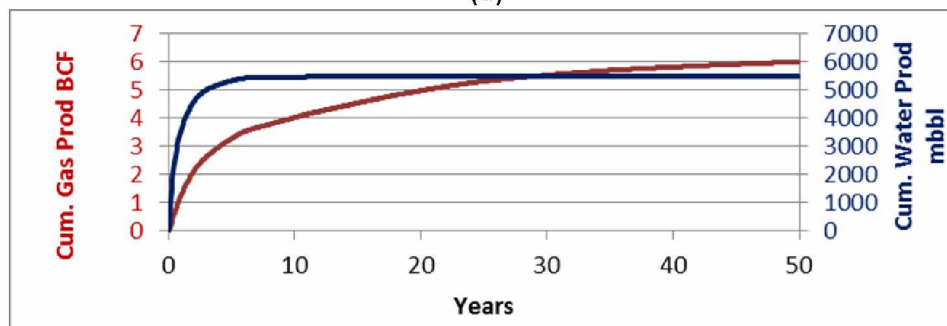


(b)

Figure 15 Case C well production rates (a) and cumulative production (b).
 [160 acre spacing, vertical completion, 51% average initial hydrate saturation]

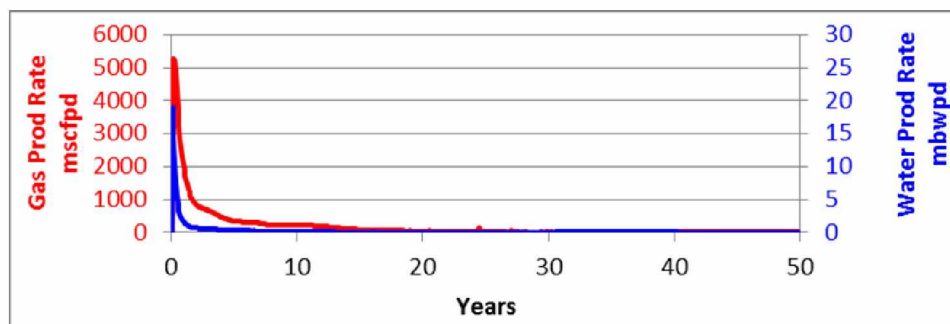


(a)

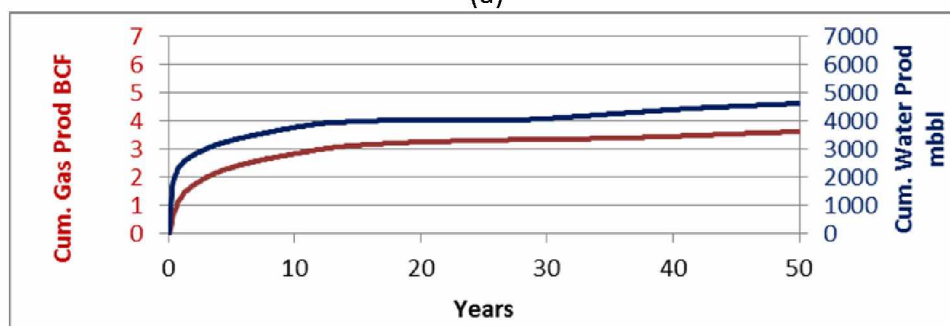


(b)

Figure 16 Case D well production rates (a) and cumulative production (b).
 [320 acre spacing, horizontal completion, 75% average initial hydrate saturation]

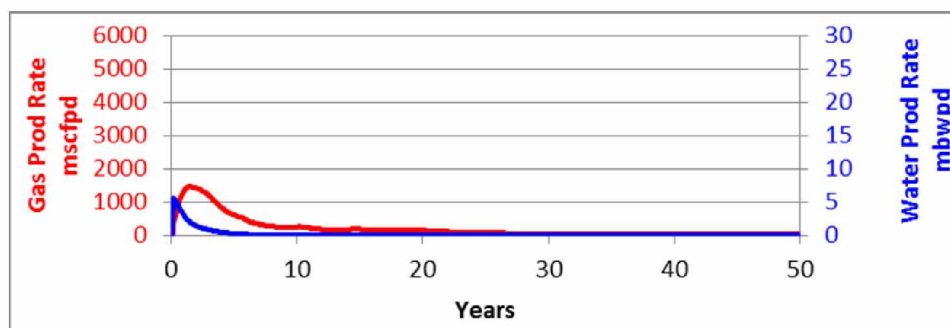


(a)

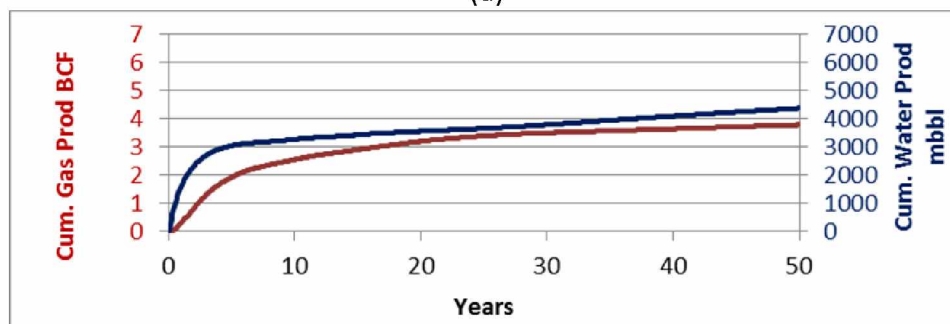


(b)

Figure 17 Case E well production rates (a) and cumulative production (b).
 [160 acre spacing, horizontal completion, 75% average initial hydrate saturation]



(a)



(b)

Figure 18 Case F well production rates (a) and cumulative production (b).
 [160 acre spacing, vertical completion, 75% average initial hydrate saturation]

3.3 Development Timing

Development of unconventional resources, such as shale gas and heavy oil, typically occurs in phases. Each phase, if successful, would lead to progressive expansion. The phases considered in the success-case gas hydrate resource development are 1) single-well pilot test, 2) multi-well pilot test, 3) limited initial development, and 4) full scale development. Each phase will be discussed in further detail below using the 320 acre well spacing for illustration.

3.3.1 Stage 1 - Single-Well Pilot Test

The first step in hydrate development would be to drill a single-test pilot well and produce it for an extended period of time (e.g. 2 years). As with the Mt. Elbert and Ignik Sikumi wells, this would allow additional reservoir data collection. More importantly, it would provide longer-term production data, and allow the producer to test the well's performance under a variety of conditions and production scenarios. If the well proves to be a poor producer, the well would be abandoned and further development would likely be canceled. However, if successful, the collection of longer term production data would allow the producer to more confidently history match the reservoir model and make the determination whether the reservoir has a higher degree of heterogeneity and lower average initial hydrate saturation, making Cases A through C more representative, or a lower degree of heterogeneity and higher average initial saturation, making Cases D through F more representative. The results would drive the design of the multi-well pilot test. Due to the low costs and production from this single-well pilot test, it is not factored into the full scale economic evaluation.

3.3.2 Stage 2 - Multi-Well Pilot Test

Following completion of a successful single-well long-term production test, a multi-well pilot test would be initiated. Several wells (est. 18) could be drilled from existing drill sites: PBU L and V Pad (Figure 19). It is assumed that the gas and water produced from these wells would be processed at the existing separation facility:

Gathering Center 2. This pilot would be more representative of a larger scale development, allowing the producer to define the variance of hydrate well productivity, while minimizing capital expenditure.

The surface infrastructure required for this stage would include well lines connecting the hydrate wellheads to the existing manifold buildings and new tie-ins to the existing large diameter flowline.

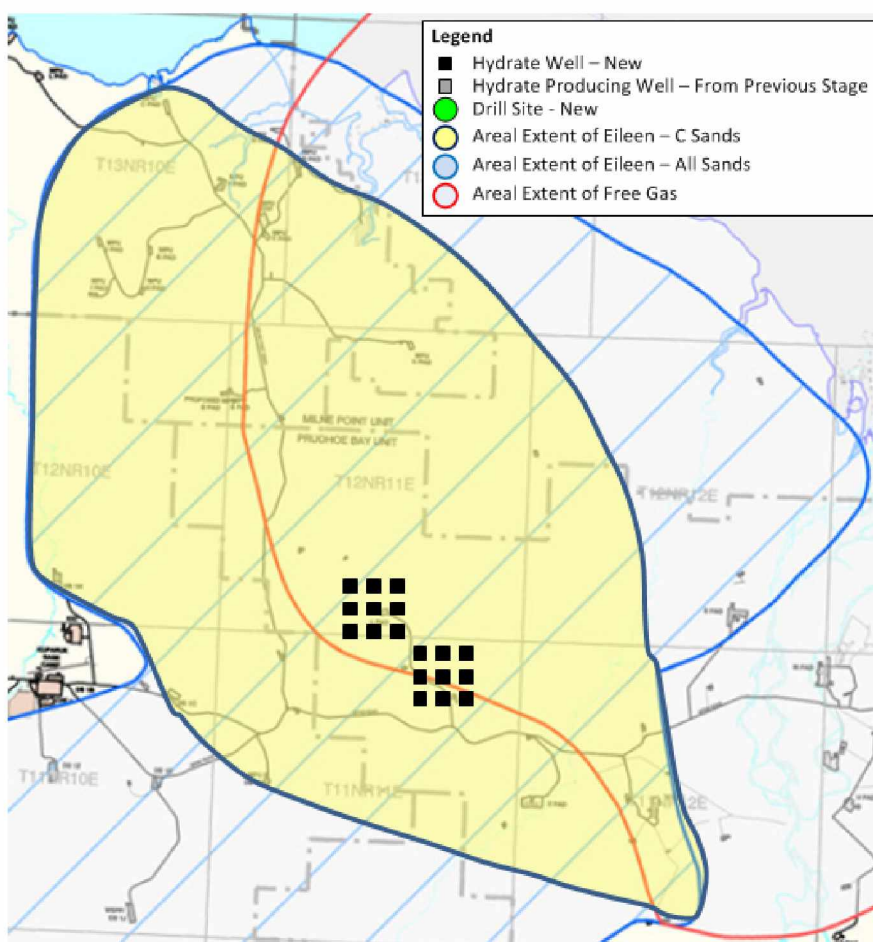


Figure 19 Stage 2 Multi-Well Pilot Test
(modified from Wilson, 2011)

3.3.3 Stage 3 - Limited Initial Development

Assuming the multi-well pilot test is successful, a larger scale development would follow. A larger number of wells (est. 98) would be drilled from the remaining



Full scale development would follow with 320 acre wells throughout the structure. This would require significant capital investment: 510 new wells would be

drilled from 60 new drill sites (Figure 21). The surface infrastructure required would include separation, gas dehydration, gas compression, and metering facilities on each drillsite in addition to an export flowline connecting the drillsite to the GTP.

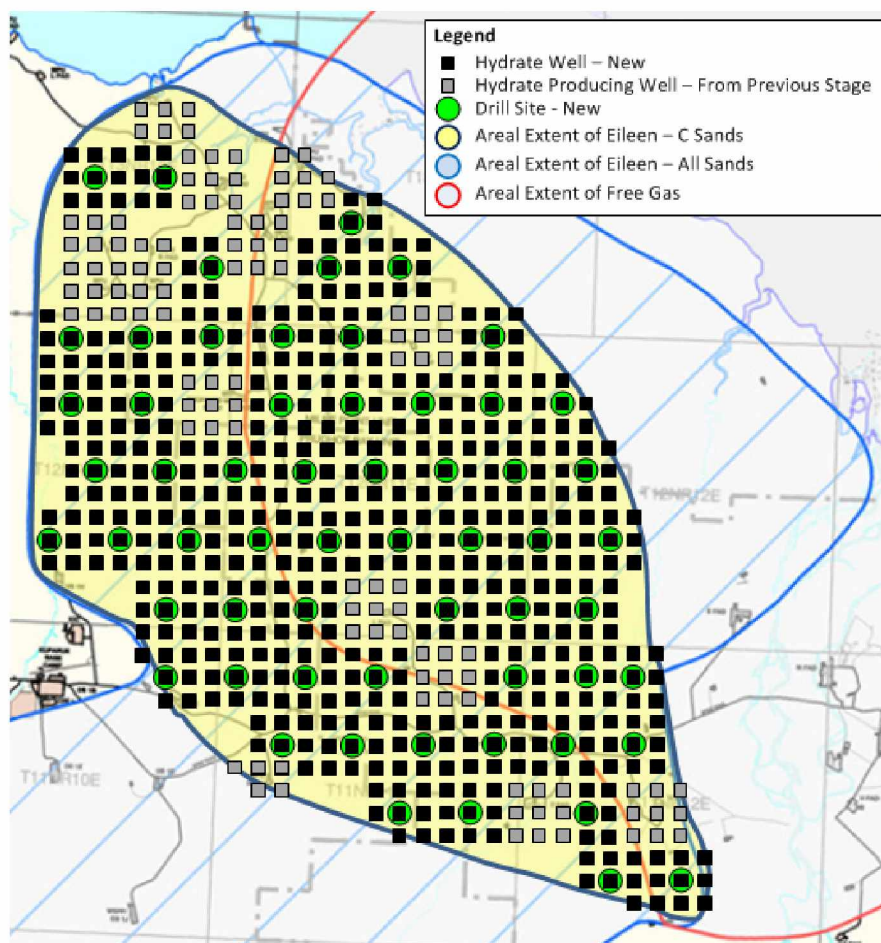
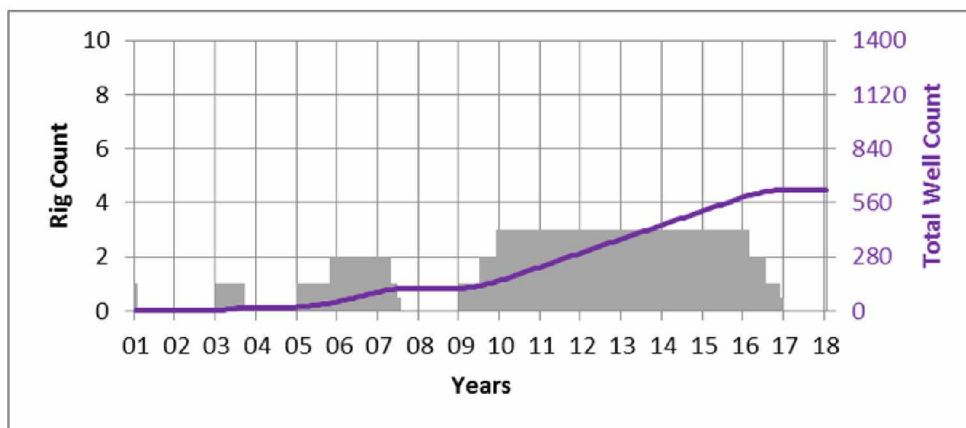


Figure 21 Stage 4 Full Scale Development
(modified from Wilson, 2011)

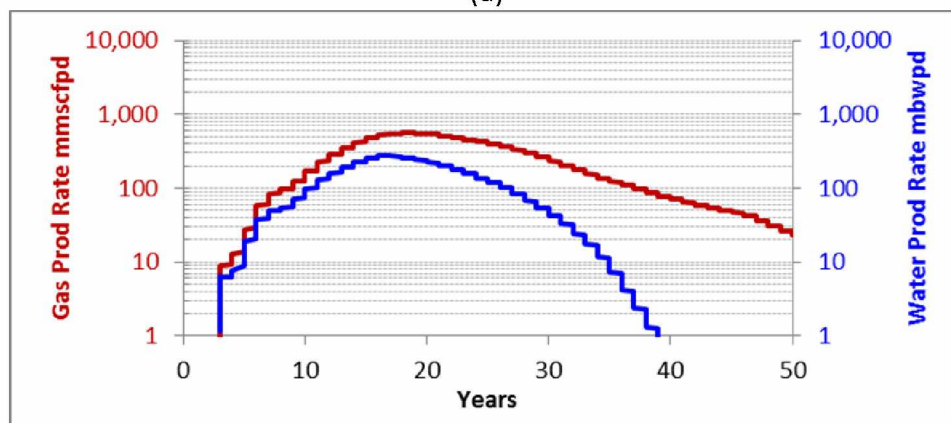
3.4 Regional Production Profiles

A production model was built in Excel in order to generate regional production profiles assuming a maximum field life of 50 years. Drilling schedules have been proposed for each of the development scenarios described above. In all six scenarios, one long term test well would be drilled in year one and tested for two years; the Stage 2 wells would be drilled during year three; Stage 3 wells would begin being

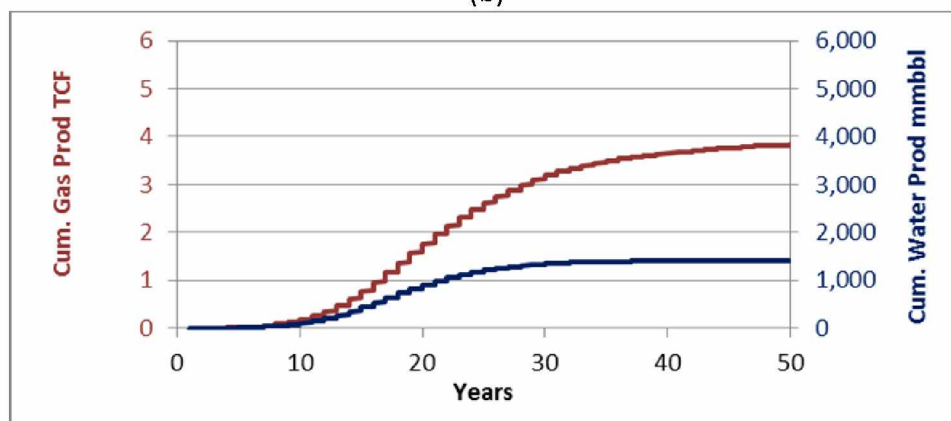
drilled in year 5, ramping up in year 6 and reaching completion in year 7; Stage 4 wells would begin being drilled in year 9, rig activity would ramp up throughout the year reaching a peak in year 10 and conclude in year 16. It was assumed that one rig could drill two horizontal wells, with a length of ~4,300' measured depth (MD), and four vertical wells, with a length of 2,300' MD, per month. The total well count reaches 626 for Cases A and D, the development scenarios with wells spaced at 320 acres; this increases to 1,251 for Cases B, C, E and F, the development scenarios with wells spaced at 160 acres. The rig count was doubled in order to drill the additional wells and develop the resource within 50 years. Less aggressive drilling scenarios are an option, but were not considered in this study. Well production volumes were assumed to be additive at the expected spacing. The drilling progression and production forecasts, both daily and cumulative, are provided in Figure 22 through Figure 27.



(a)

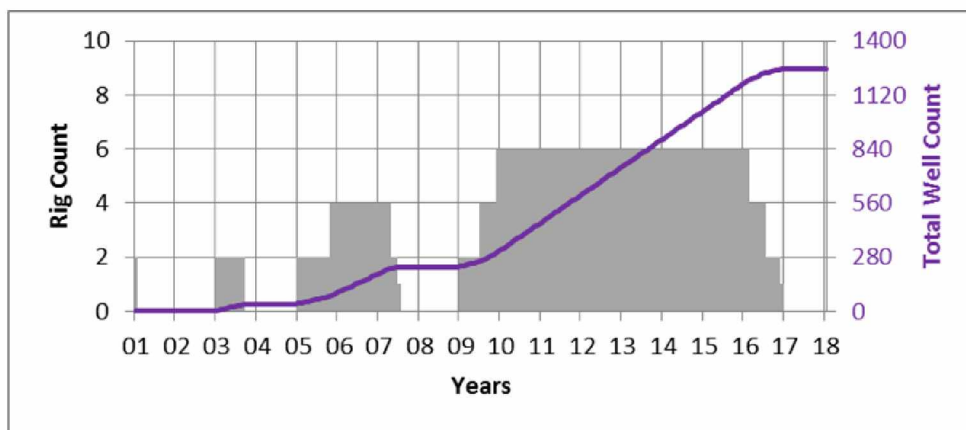


(b)

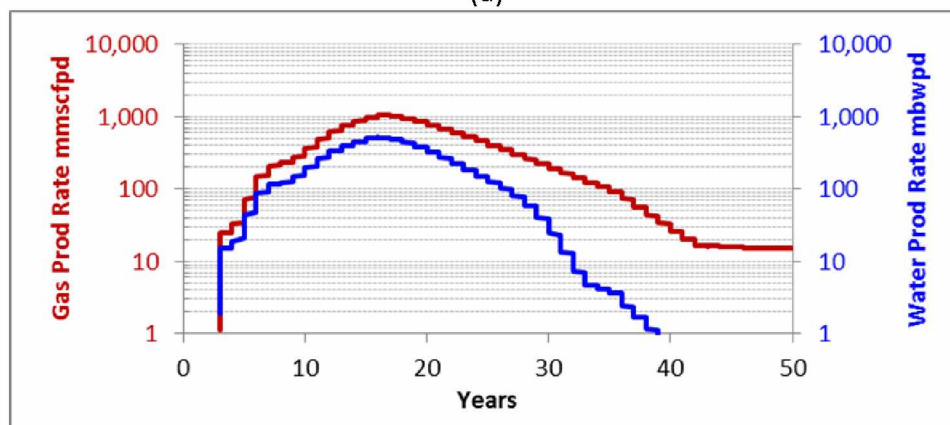


(c)

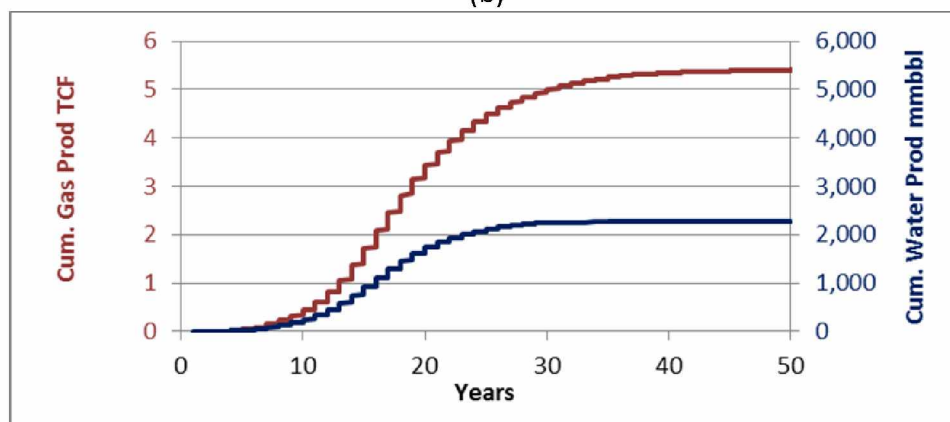
Figure 22 Case A drilling progression (a) and regional production forecasts (b, c).
 [320 acre spacing, horizontal completion, 51% average initial hydrate saturation]



(a)

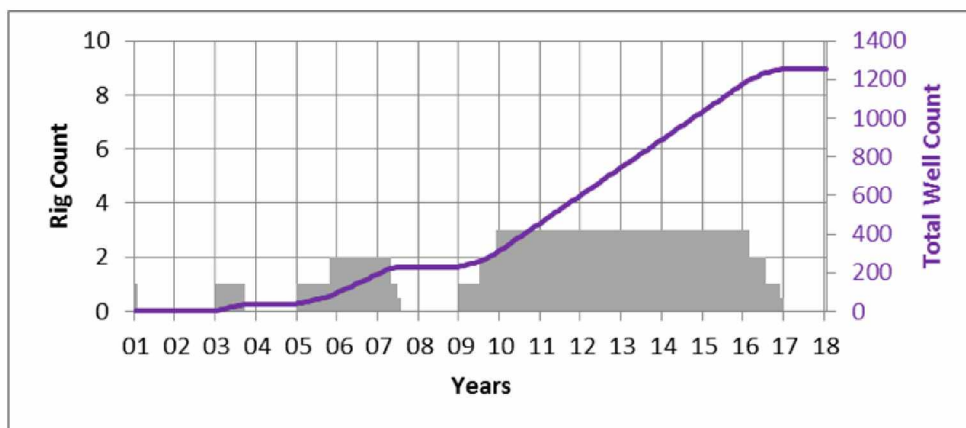


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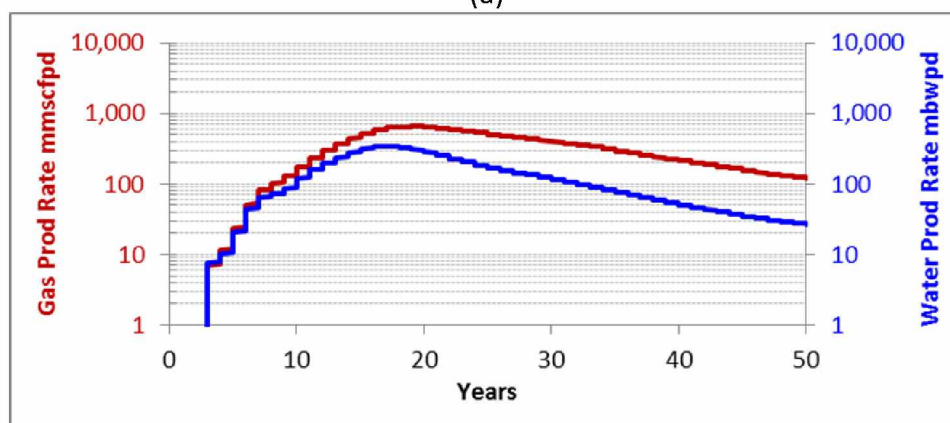


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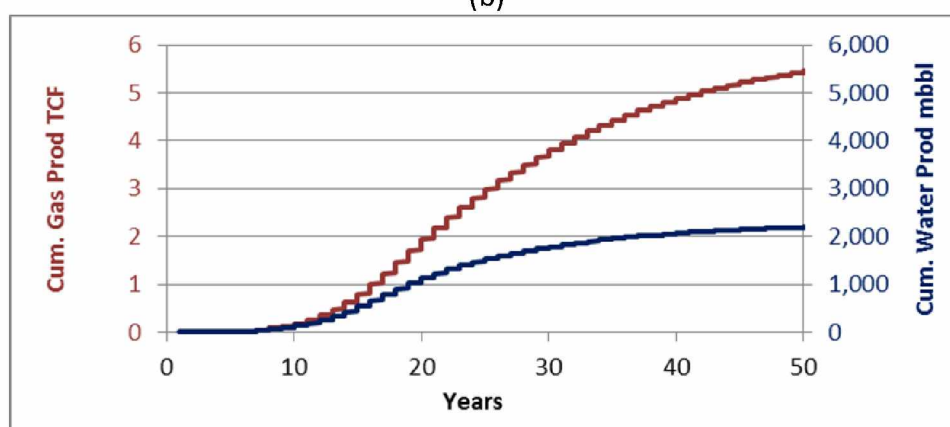
Figure 23 Case B drilling progression (a) and regional production forecasts (b, c).
 [160 acre spacing, horizontal completion, 51% average initial hydrate saturation]



(a)

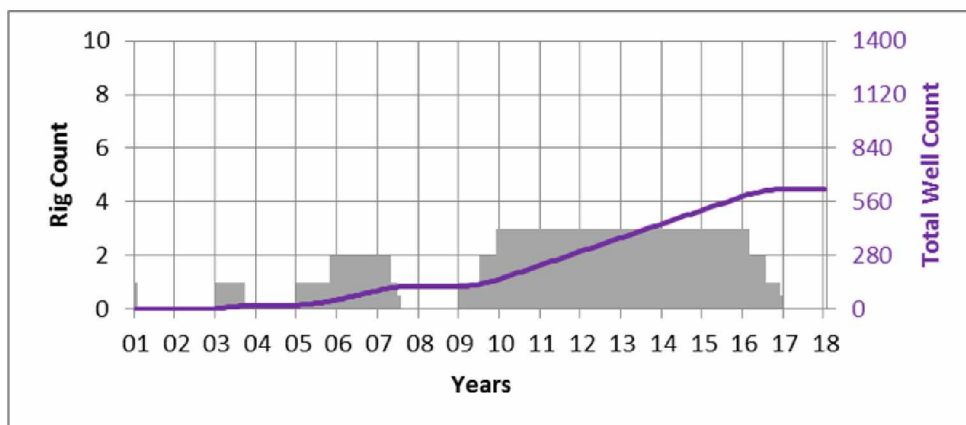


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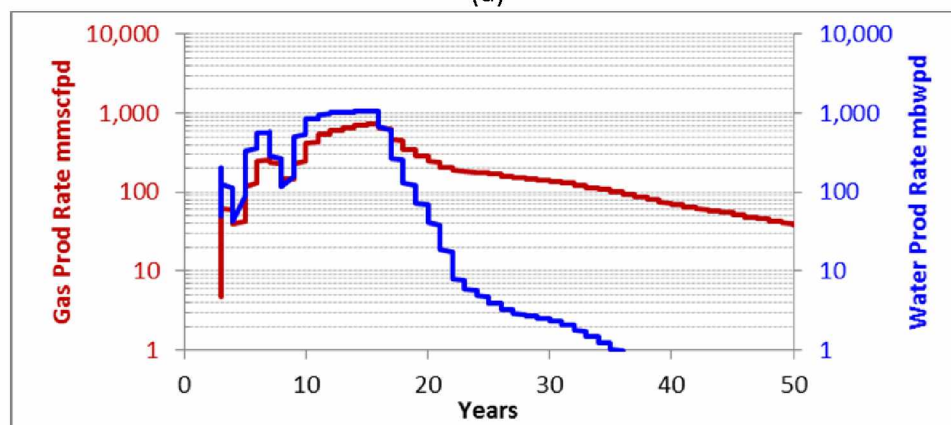


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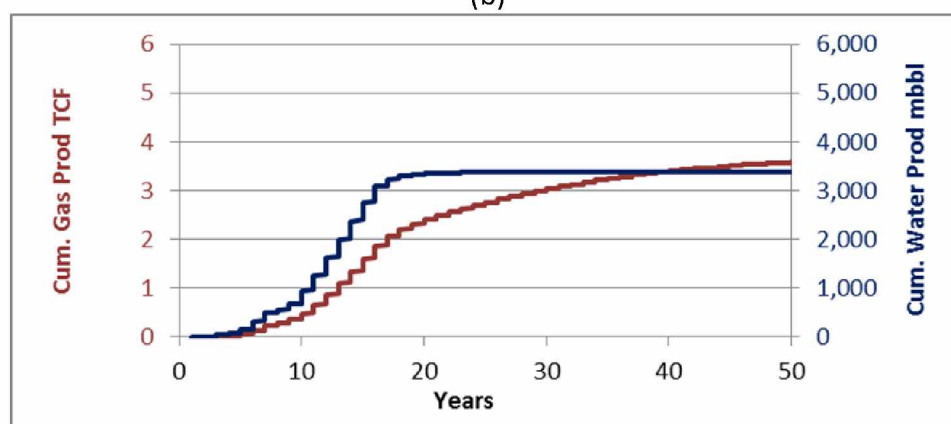
Figure 24 Case C drilling progression (a) and regional production forecasts (b, c).
 [160 acre spacing, vertical completion, 51% average initial hydrate saturation]



(a)

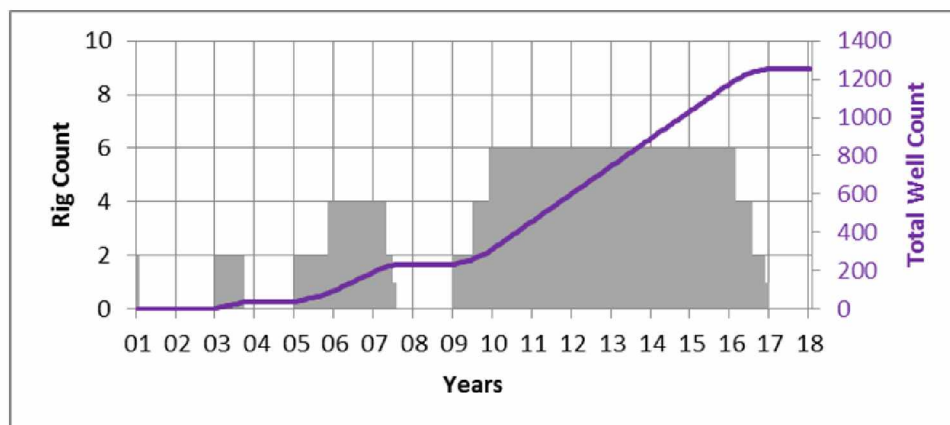


(b)

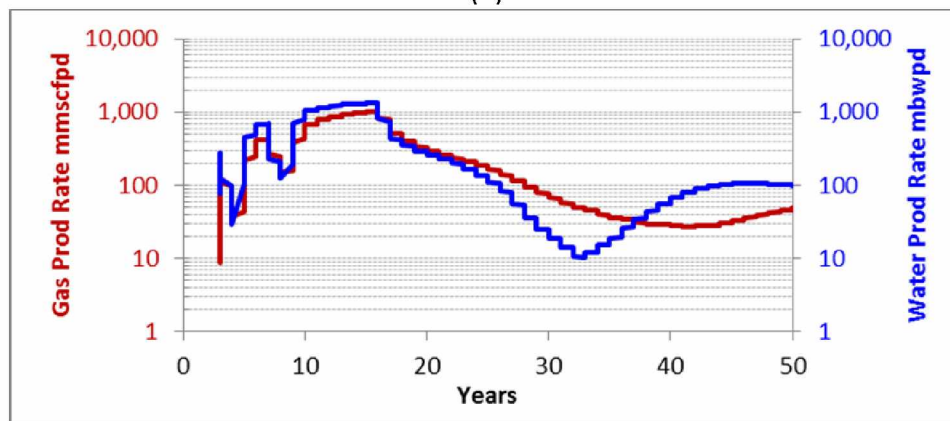


(c)

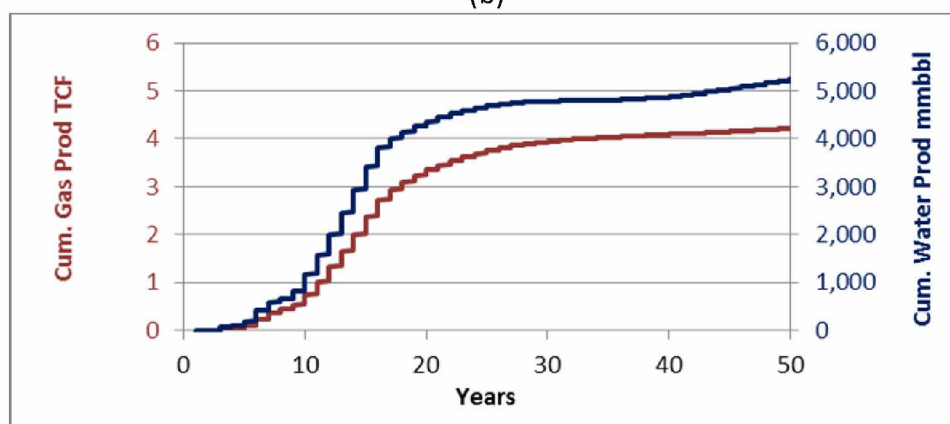
Figure 25 Case D drilling progression (a) and regional production forecasts (b, c).
 [320 acre spacing, horizontal completion, 75% average initial hydrate saturation]



(a)

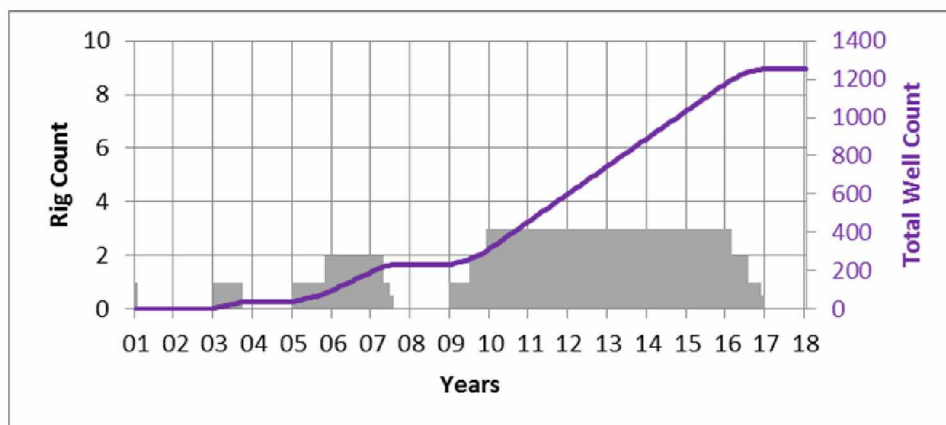


(b)

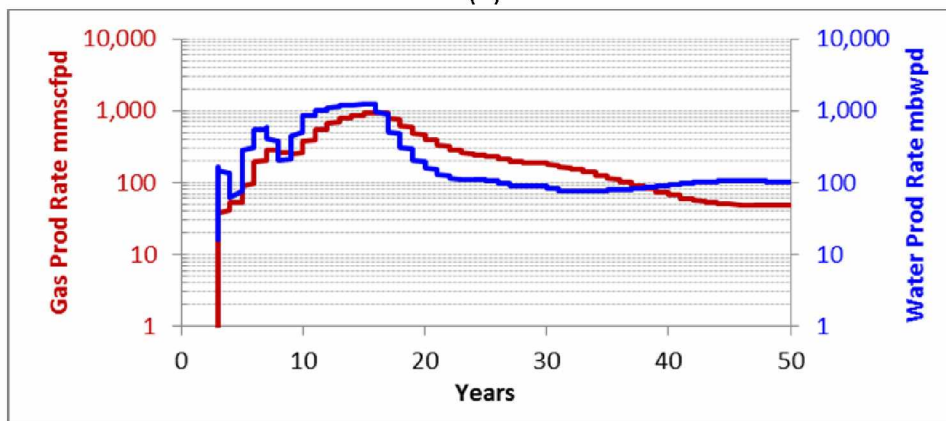


(c)

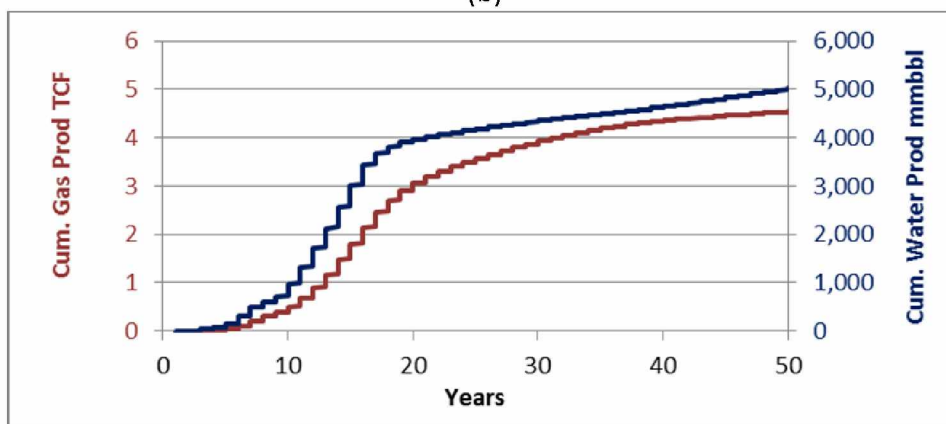
Figure 26 Case E drilling progression (a) and regional production forecasts (b, c).
 [160 acre spacing, horizontal completion, 75% average initial hydrate saturation]



(a)



(b)



(c)

Figure 27 Case F drilling progression (a) and regional production forecasts (b, c).
 [160 acre spacing, vertical completion, 75% average initial hydrate saturation]

In order to calculate the recovery factor for each regional production scenario, it was necessary to estimate the original gas in place (OGIP) for the upper C sand. This value was available for each of the four reservoirs modeled by Jennifer Blake (2015): 1) 320 acre reservoir with 51% average initial hydrate saturation, 2) 160 acre reservoir with 51% average initial hydrate saturation, 3) 320 acre reservoir with 75% average initial hydrate saturation, and 4) 160 acre reservoir with 75% average initial hydrate saturation. The areal extent of the C sand was estimated from Figure 19 to be 213,392 acres. The OGIP values for the four reservoir models were scaled up to obtain OGIP estimates for whole of the upper C sand. Then, the OGIP values for the two different initial hydrate saturation reservoirs was averaged to give the following: OGIP for 51% average initial hydrate saturation is 10.6 TCF, and OGIP for 75% average initial hydrate saturation is 16.9 TCF. The EUR and total methane recovery factors following 50 years of production are summarized in Figure 28. While these volumes and recovery rates may be technically recoverable, the life of the field will be dependent on the economics.

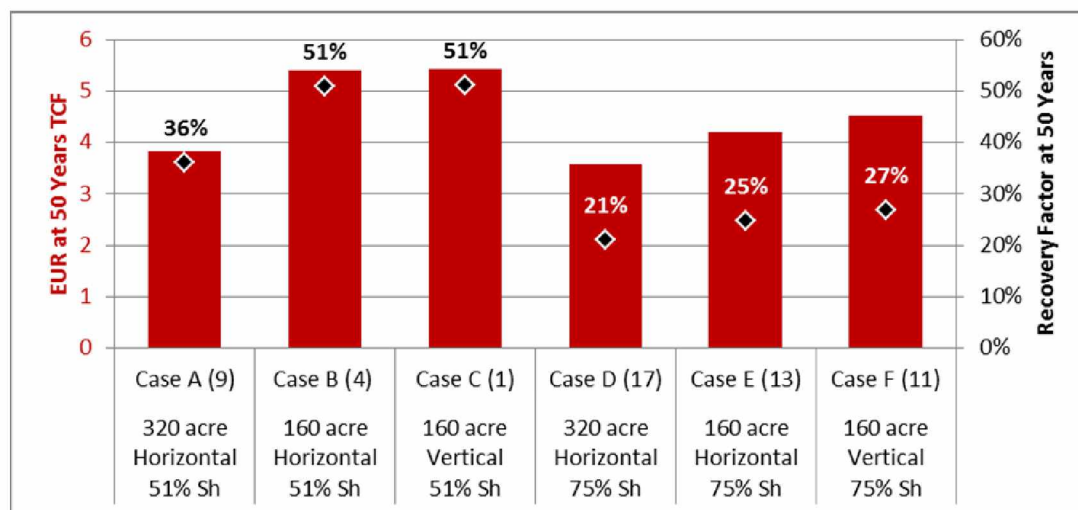


Figure 28 Estimated Ultimate Recovery and Recovery Factor at 50 Years
Note: Numbers in parentheses refer to case study numbers of Blake (2015).

3.5 Flow Assurance

Hydrate reformation is a flow assurance threat in the well bore, surface flowlines and separation equipment. The hydrate curve for pure methane and ice curve are provided in Figure 29. The initial reservoir conditions and target flowing bottomhole pressure were obtained from the reservoir modelling studies completed by Jennifer Blake using CMG STARS (Blake, 2015). The target flowing bottomhole pressure of 390 psi (2.7 MPa) was selected to prevent the reservoir pressure dropping below the lower quadruple point, where four phases (ice, hydrate, liquid water and hydrocarbon gas) could be found in equilibrium, and risking ice forming in the reservoir. Flowing wellhead conditions at peak water production were obtained through well bore modelling in Pipesim 2010.1, a steady-state flow modelling application, assuming the target flowing bottomhole pressure of 390 psi is achieved. According to the reservoir modelling, this is only achieved late in field life (~50 years); therefore, the wellhead conditions plotted in Figure 29 represent the highest pressure that would be seen. The fluids will be in the hydrate region as they are produced through the wellbore.

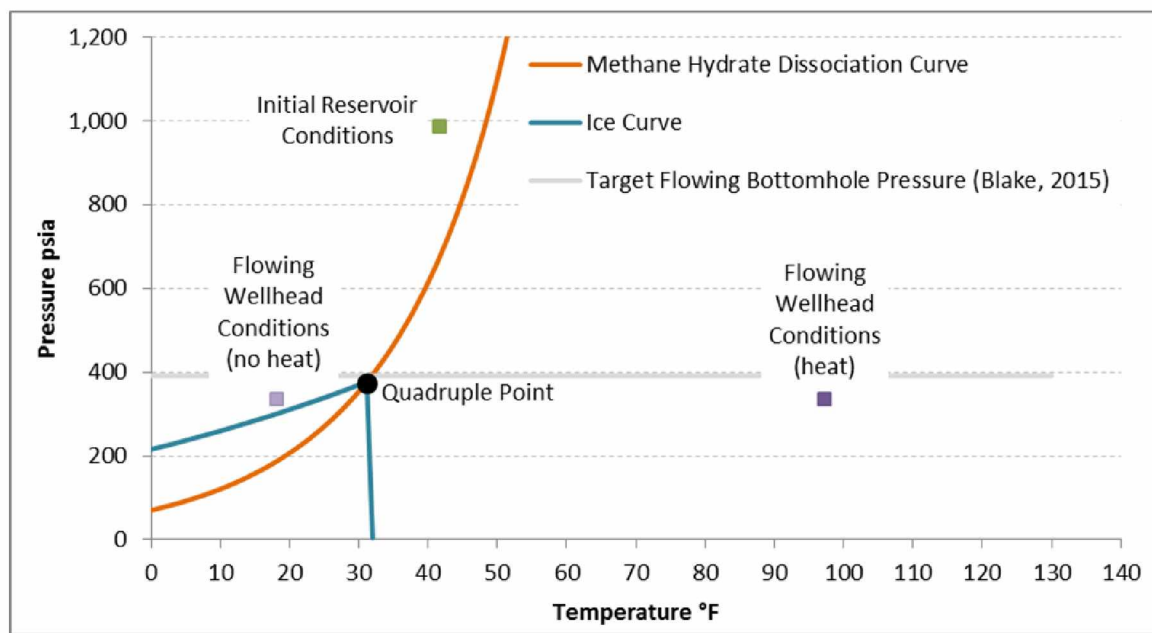


Figure 29 Hydrate Curve and Operating Conditions

In order to mitigate hydrate reformation in the wellbore, it is necessary to provide wellbore heating. It is assumed that a well bore design similar to that used with the Ignik Sikumi well would be used; this would involve pumping heated power fluids down the well annulus and producing the power and production fluids using downhole jet pumps. Warm power fluids will be supplied by a source-water well producing from the Ivishak aquifer; the source water is approximately 200°F subsurface, and it is assumed that they would maintain an average temperature of 100°F in the well's inner annulus. Well bore heating may be detrimental to the permafrost stability, especially at the closer 160 acre well spacing. The heat transfer calculations for this process were outside the scope of this project. However, there are measures that could be taken, such as the use of insulated tubing, which has proved effective in steam assisted gravity drainage production.

The well design will also need to allow downhole injection of a thermodynamic hydrate inhibitor, methanol, in order to mitigate hydrates that may reform when there are upsets in production and the well is shut-in. This was a key lesson learned from the Ignik Sikumi well. Well lines carrying the fluids from the wellhead to the production manifold building would need to be heat traced and insulated.

For wells drilled from existing drillsites, the assumption has been made that the fluids (both gas and water) could be tied into the existing flowlines and processed at their respective facilities. The other fluids being carried in these flowlines are primarily from both light oil and viscous oil formations, which are much deeper and hotter than hydrate accumulations. The addition of the hydrate production fluids to the large diameter flowline will not be significant enough to bring the operating conditions back within the hydrate region. The additional gas production has the potential to alleviate fuel gas demand in MPU and KRU facilities. However, it may pose more of a complication if the existing flowlines and/or separation are already gas constrained.

For wells drilled from new drillsites, dedicated to hydrate production, it is assumed that onsite separation would be the most practical course of action. The gas

would need to be transported to the GTP through flowlines with an average length of ~22 miles; even with an inlet temperature of ~90°F, the fluids would likely cool and drop within the hydrate region before reaching plant. Hydrate inhibition, either through heat tracing and insulation or methanol injection, in cross-country flowlines would be cost prohibitive and high risk; these scenarios were not considered in this analysis. Instead, the gas will be dehydrated at each drillsite, targeting a dew point of -40°F.

3.6 Estimation of Capital and Operating Expenditure

The capital expenses (CAPEX) for the regional development of ANS hydrates were generated using Oil & Gas Manager (OGM) Version 1.7.8, a planning software and costing application by Siemens. One drillsite was modeled for each of the production scenarios listed in Table 1. A high-level overview of the process followed and assumptions made are described below using Case A for illustration; similar methodology was applied to the remaining scenarios.

The first step was specifying the erection site, Alaska, which allows region specific costs to be used by OGM. The drillsite incorporates one central processing facility (CPF) located on one wellsite, and is sized for a peak gas production rate of 9.2 MMCFD (Figure 30). The winterization option was selected; this incorporates insulation, heating, ventilating, and air conditioning (HVAC) to the facilities to maintain an internal temperature of 41°F, which will affect the topside steel weight, HVAC sizing, and power requirement. The reservoir fluid was specified as 99.8mol% methane (C1) and 0.2mol% Pseudo #1 (C7+); this was set as the global fluid composition for the field (Figure 31). Initial attempts to model a reservoir fluid composition of 100mol% methane led to modelling errors within OGM because the software (Version 1.7.8) is set-up to expect a small amount of hydrocarbon liquid to flash in the first stage separator; while this is not technically true for a hydrate production scenario, it allows the model to run to completion with only a nominal impact on the overall estimate.

Facility [Drillsite (Onsite Separation)]

Erection Site: **Alaska**

Central Processing Facility

Name: **Drillsite (Onsite Separation)** Specify CPF

Gathering Stations: **0** Gathering Stations

Local Wellsites: **1** Specify Wellsites

Option for Terminal: ☐ Specify Terminal

Option for Gravel Island: ☐ Specify Gravel Island

Facility Type: **GAS PRODUCTION** Graphical View

Hi-Level Information

Crude Production Rate: **20.00** **kbpd**

Gas Export Rate: **9.20** **mmscfd**

Winterization Option: ☒

Figure 30 OGM Drillsite Specification

Specifications for Reservoir Fluid on a Wellsite [WS1]

☒ Specify Gas/Oil Ratio
10000.00 **scf/bbl**

☒ Specify Composition

Component Mole %

Fill Composition

| | |
|-----------|-------|
| N2 | 0.00 |
| CO2 | 0.00 |
| H2S | 0.00 |
| C1 | 99.80 |
| C2 | 0.00 |
| C3 | 0.00 |
| iC4 | 0.00 |
| nC4 | 0.00 |
| iC5 | 0.00 |
| nC5 | 0.00 |
| nC6 | 0.00 |
| Pseudo #1 | 0.20 |
| Pseudo #2 | 0.00 |

Normalize

Global Reservoir Fluid Template

Set Template View Template Use Template for This Fluid

Crude Handling

Wax Appearance Temperature: **80.00** **°F**

Hydrate Prediction Method: **GPSA**

Pseudo Component Properties:

☒ ERBAR Method

| | Pseudo #1 | Pseudo #2 |
|---------------------|--------------------------|--------------------------|
| API Gravity: | 30.00 °API | 30.00 °API |
| Avg. Molecular Wt.: | 250.00 | 250.00 |

☒ Critical Property Method

| | Pseudo #1 | Pseudo #2 |
|---------------------|-------------------------|-------------------------|
| Normal Boiling Pt.: | 0.00 °F | 0.00 °F |
| Critical Temp.: | 0.00 °R | 0.00 °R |
| Critical Pressure: | 0.00 psia | 0.00 psia |

Figure 31 OGM Reservoir Fluids Specifications - Composition

The total gas export rate was set at 9.2 MMCFD; the flowing wellhead pressure and temperature were set at 335 psi and 97 °F, respectively. The produced water handling capabilities required to achieve the peak water rate is 4.7 MBD.

Reservoir Fluid [WS1]

☒ By Total Site Export Rate

Process Simulation Basis: **GAS FLOWRATE**

Total Site Export Rate

Crude Production Rate: 10.00 kbpd

Gas Export Rate: 9.20 mmscfd

Condensate Rate: 10.00 kbpd

Specify the total design flowrate including the local fluid and all remote sites.

☐ By Local Reservoir Fluid

Local Reservoir Fluid Rate: 2000.00 lb-mol/hr

Flowing Wellhead Pressure: 335.00 psig

Flowing Wellhead Temperature: 97.00 °F

Produced Water Rate to Achieve Peak Fluids: 4.70 kbpd

Stream Compositions: **Specify**

Figure 32 OGM Reservoir Fluids Specifications - Production Rates

The drillsite was defined as having nine production wells with an average depth of 4300 feet (Figure 33). Note that this is the measured depth of a horizontal well; the true vertical depth (TVD) would be 2300 feet and extend a further 2000 feet horizontally through the hydrate accumulation. Default values were generated by OGM for the shut-in wellhead pressure (835 psig) and production manifold design pressure (385 psig). The “corrosion inhibitor injection” option was selected in order to size tankage for a hydrate inhibitor. The default injection rate of 0.03 gallons per minute was used and an average flowing bottomhole pressure of 390 psi was assumed. Lift pumps cannot be specified in OGM for gas production wells, only liquids. However, wells would require jet pumps for liquid unloading and circulation of warm power fluids. An estimated

drilling cost of \$270/foot was reported by Howe (2004); it was assumed that this is representative of drilling costs in the continental United States, and that the drilling cost in Alaska would be 50% higher (\$405/foot). Assuming an inflation rate of 9% translates to \$1045/foot in 2015 and \$1608/foot in 2020. It was assumed that 80% of the cost would be intangible (time and manpower) and 20% would be tangible (tubing, jet pumps and wellheads). All default values were retained for the well line specifications; well lines will flow from the wellheads to the CPF and enter the separation system at 275 psig.

The screenshot shows the 'Wellheads & Manifolds [WS1]' window with the following settings:

| Section | Parameter | Value | Unit |
|-------------------------------|-------------------------------------|-------------------------------------|---------|
| Number of Wells | Production | 9 | |
| | Avg Prod Well Depth | 4300.00 | feet |
| | Water Injection | 0 | |
| | Gas Reinjection | 0 | |
| Pressure | Shut-In Wellhead | 835.00 | psig |
| | Production Manifold Design | 385.00 | psig |
| Lift Pumps | Type | NONE SPECIFIED | |
| | Quantity | 9 | |
| | Absorbed BHP/Pump | 80.00 | |
| Wellhead Start-Up Heater | Allocate | <input checked="" type="checkbox"/> | |
| | Type | DIRECT FIRED | |
| | Duty | 1.50 | mmBTU/h |
| Corrosion Inhibitor Injection | Allocate | <input checked="" type="checkbox"/> | |
| | Injection Pump Design Rate | 0.030 | USgpm |
| | Average Flowing Bottomhole Pressure | 390.00 | psig |

Figure 33 OGM Wellheads & Manifolds Specifications

A graphical representation of the CPF is provided in Figure 34. The number of local production wells in Wellheads & Manifolds screen was set to zero; this caused the Reservoir Fluids button to become inactive. The separation system at the CPF was limited to one stage given that the fluids will be arriving at low pressures. All default settings were retained in the specification of the separator (Figure 35).

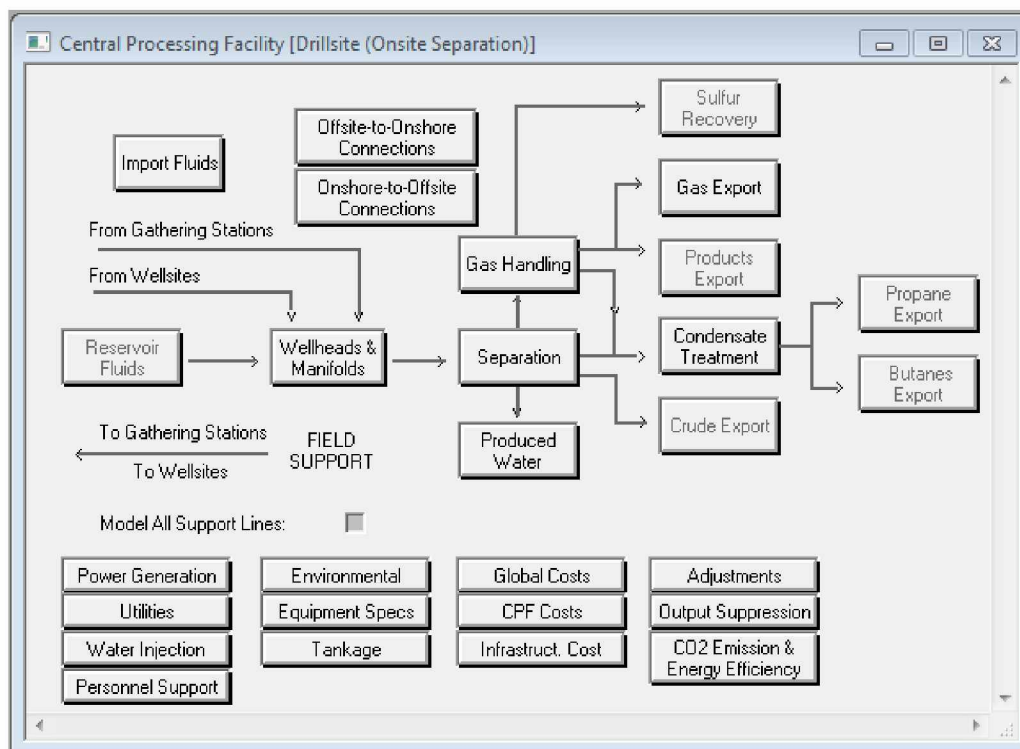


Figure 34 OGM Graphical Representation of Central Processing Facility

Figure 35 OGM Separator Specifications

The produced water will be reinjected into a subsurface disposal zone. OGM has a “sour water stripper” option for situations where the produced water will be sour due to the presence of hydrogen sulfide. This will be unnecessary as the hydrate production fluids should be sweet (contain no hydrogen sulfide). The system is sized to handle the peak water production rate of 4.7 MBD (Figure 36).

The screenshot displays a software window titled "Produced Water Treatment [Drillsite (Onsite Separation)]". The window contains a list of configuration parameters for water treatment, each with a corresponding input field or dropdown menu. The parameters and their values are as follows:

| Parameter | Value |
|--|-------------------------------------|
| Design Rate: | 4.70 kbpd |
| Disposal Mode (After Oil Removal): | REINJECTED INTO A SUBSTRATA HORIZON |
| Export/Reinjection Pressure: | 800.00 psig |
| Option for Pretreatment Heat | <input checked="" type="checkbox"/> |
| Min. Treatment Temperature: | 130.00 °F |
| Sour Water Stripper Option: | NO SOUR WATER STRIPPER ALLOCATED |
| Disposal Pump Configuration: | 2 X 100 % ELECTRICAL |
| Filter: | NO FILTER |
| API Classifier Option: | <input checked="" type="checkbox"/> |
| Corrugated Plate Interceptor (CPI) unit: | <input checked="" type="checkbox"/> |
| Flotation/Hydrocyclone Unit Option: | NEITHER |
| Flash Tank Residence Time: | 2.50 min |
| Option to Model the Export Line: | <input checked="" type="checkbox"/> |
| Diameter of the Export Pipeline: | 0.00 in |
| Length of the Export Pipeline: | 10.00 mi |
| Outlet Pressure: | 175.00 psig |
| Pipeline Design Construction Factor: | CROSS COUNTRY LOCATIONS 0.72 |
| Pipeline Heat Transfer Coeff.: | 3.00 BTU/hr |
| Pipeline Minimum Yield Strength: | 60,000 PSI API 5LX60 |

Figure 36 OGM Produced Water Treatment Specifications

All gas will be dehydrated, compressed and exported for sale. The dehydration system will be required to achieve an outlet water dew point temperature of -40°F in order to prevent the formation hydrates in the gas pipeline (Figure 37, Figure 38). It will

then be compressed to an export pressure of 395 psig (Figure 39). An average export pipeline length of 22 miles was assumed (Figure 40). A simplified process flow diagram is provided in Figure 41.

Figure 37 OGM Gas Handling Specifications

Figure 38 OGM Gas Dehydration Specifications

Gas Compression [Drillsite (Onsite Separation)]

Export Gas Compression

Driver: **COMBUSTION GAS TURBINE**

Number of Trains: **1**

% Flow Rate/Train: **100.00** %

Turbine Driver: **INTERNALLY DETERMINED**

Export Temp: **120.00** °F

Number of Packages: **1**

A B C D E

Gas Compression

Max Compression Ratio: **8.00**

Max Inlet Temp: **120.00** °F

Max Outlet Temp: **400.00** °F

Intercooler Outlet Temp: **120.00** °F

Min ICFM for Centrifugal: **300.00** ACFM

Minimum Centrifugal Compressor Efficiency: **0.40**

Fuel Gas Compression

Number of Trains: **1**

% Flow Rate/Train: **100.00** %

Figure 39 OGM Gas Compression Specifications

Gas Export [Drillsite (Onsite Separation)]

Export Gas Pipeline:

Pipeline Modeling Option: **MODEL WITH FACILITY**

Destination: **USER SPECIFIED**

Name: **Point of Sale**

Length: **22.00** mi

Pipeline Outlet Pressure: **175.00** psig

Construction Design Factor: **CROSS COUNTRY LOCATIONS 0.72**

Heat Transfer Coefficient: **3.00** BTU/hr-ft²-°F

Minimum Yield Strength: **60,000 PSI API 5LX60**

Independent Pipeline Model Specifications **Additional Pipeline Specifications**

Gas Pipeline Segments:

Number of Segments: **1**

| | Inlet | Elevation | Length | Diameter | Wall Thickness | Compressor Stations | Suction Pressure | Discharge Pressure |
|------------|----------|-----------|----------|----------|----------------|---------------------|------------------|--------------------|
| Segment: 1 | 100 feet | 100 feet | 22.00 mi | 0.00 in | 0.00 in | NO | 0.00 psig | 0.00 psig |

Figure 40 OGM Gas Export Pipeline Specifications

Operating expense (OPEX) is typically divided into two main categories: 1) field operating or direct costs, which include costs related to personnel, consumables, utilities, maintenance, product processing, product transportation, well workovers, logistics and modification, and 2) indirect costs, which include administrative and corporate overhead, technical support, business expenses, insurance, taxes, fees and decommissioning costs. While OGM provides a framework for calculating and documenting OPEX based on a typical set of cost categories, the software does not maintain region-specific operating cost data. The annual OPEX has been estimated as follows: The direct OPEX is assumed to be 5% of the total CAPEX (Nederlof, 2015) plus \$0.15/MCF (Howe, 2004). The indirect OPEX that are included are the administrative overhead and technical support costs, each of which are each assumed to be 5% of the direct OPEX (OGM default).

The primary output generated by the OGM model is a CAPEX cost. The cost is itemized to allow the user to differentiate between the cost of material, construction, engineering and project management for well sites, well lines, the CPF, export lines and general infrastructure. The final cost incorporates a 10% contingency. The work breakdown cost summary for a new drillsite, based on the capacity requirements for Case A (9), is provided in Table 2. The cost of upgrading and producing from an existing drillsite is assumed to equal the well site and well line cost. The drillsite sizing basis, CAPEX and annual direct OPEX values are provided for each of the six production scenarios in Table 3.

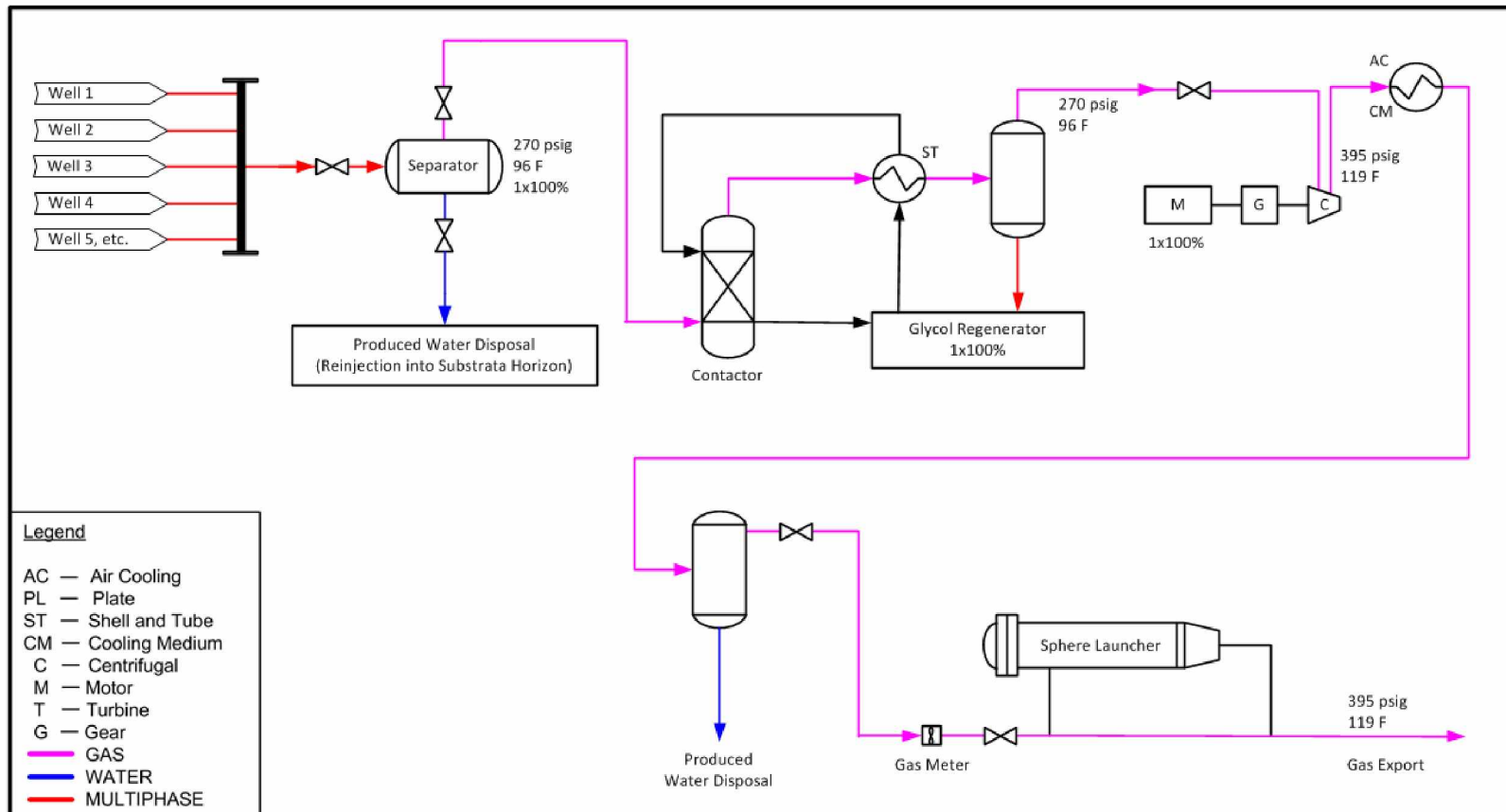


Figure 41 OGM Process Flow Diagram for Onsite Separation System

| Work Breakdown Structure | Material | Construction | Engineering & Project Management | Other | Subtotal | Contingency (10%) | Total |
|-----------------------------------|---------------|---------------|----------------------------------|---------------|---------------|-------------------|---------------|
| | USD (000) | USD (000) | USD (000) | USD (000) | USD (000) | USD (000) | USD (000) |
| Well Sites | 652 | 457 | 277 | 21 | 1,408 | 141 | 1,549 |
| Well Lines | 66 | 243 | 81 | 31 | 420 | 42 | 462 |
| Central Processing | 21,631 | 18,290 | 13,972 | 626 | 54,520 | 5,452 | 59,972 |
| Export Lines | 530 | 3,960 | 1,152 | 548 | 6,191 | 619 | 6,810 |
| Infrastructure | 0 | 0 | 0 | 23,300 | 23,300 | 2,330 | 25,630 |
| Total - New Drillsite | 22,880 | 22,950 | 15,483 | 24,526 | 85,838 | 8,584 | 94,422 |
| Total - Existing Drillsite | 718 | 700 | 358 | 51 | 1,828 | 183 | 2,011 |

Table 2 OGM CAPEX for Drillsite with Onsite Separation - Case A

| Case Name | Gas Rate (MMCFD) | Water Rate (MBD) | Well Count - | Average Well Length (ft) | New Drillsite CAPEX (million USD) | Direct OPEX (million USD/yr) | Existing Drillsite CAPEX (million USD) | Direct OPEX (million USD/yr) |
|-------------|----------------------------|----------------------------|------------------------|---------------------------------------|--|---|---|---|
| Case A (9) | 9.2 | 4.7 | 9 | 6,517 | \$94 | \$5 | \$2.0 | \$0.1 |
| Case B (4) | 19.7 | 10.4 | 18 | 6,517 | \$105 | \$5 | \$3.2 | \$0.2 |
| Case C (1) | 10.6 | 6.0 | 18 | 4,260 | \$102 | \$5 | \$3.1 | \$0.2 |
| Case D (17) | 33.2 | 126.6 | 9 | 6,517 | \$138 | \$7 | \$3.6 | \$0.2 |
| Case E (13) | 83.4 | 205.1 | 18 | 6,517 | \$168 | \$8 | \$5.1 | \$0.3 |
| Case F (11) | 26.2 | 92.2 | 18 | 4,260 | \$132 | \$7 | \$3.5 | \$0.2 |

Table 3 OGM Drillsite Sizing Basis, CAPEX and Direct OPEX Estimates
Note: Numbers in parentheses refer to case study numbers of Blake (2015).

3.7 Economic Model

An economic model for production and cash accounting was built in MS Excel, incorporating the current State and Federal tax laws. The reader should note that many of these tax laws were written with conventional oil and gas reservoirs in mind; these laws may or may not be applied to the production of hydrates.

3.7.1 Cash Accounting & Fiscal Assumptions

All calculations were made on an annual basis. The cash flow accounting method is described below and summarized in Figure 42. The dollar values listed below are inflated to determine the equivalent value in 2020, assuming an inflation rate of 9% (Howe, 2004).

Turnover

The turnover is the gas production volume multiplied by the gas sales price. The AGDC anticipates a final consumer cost in the range of \$11.50 to \$14.50 per million British thermal units (MMBTU) according to the cost estimates and associated tariffs announced in a press release on January 9, 2015; this is based on a processing and transportation tariff of \$5.50 to \$9.75 per MMBTU, local distribution costs of either \$1.50 per MMBTU in Anchorage or \$4.00 per MMBTU in Fairbanks, and a cost of gas between \$2.00 to \$3.30 per MMBTU (AGDC, 2015). A gas heating value of 1.08 MMBTU/MCF was assumed (White, 2014).

Turnover Cost

The turnover cost is the sum of the royalty (including net profit share obligations), severance tax, ad valorem tax, hazardous substance release surcharge, and purchase costs.

- Royalty

This is compensation provided to the owner of the property for the privilege of developing and producing from a lease, and comprises a

share in the oil and gas extracted. The State of Alaska reserves all rights to all oil, gas, coal, minerals and geothermal resources, and retains surface rights granting a mineral producer access to and use of the surface in order to develop the mineral estate (AS 38.05.125(a)). Royalty agreements are established as part of the lease agreement; these can be a fixed percentage, a sliding scale or net profit shares. Royalty rates vary, according to the terms of the lease agreement, from 5% to 60%, but are most often [12.5%](#) (1/8). While royalty agreements are not normally subject to change, Senate Bill (SB) 138, signed into law on September 19, 2014, allows the Department of Natural Resources (DNR) to convert the sliding scale and net profit share royalties to fixed rate royalties by mutual agreement with the lessees (AS 38.05.180(hh)). Royalties can be taken as a portion of the oil and gas produced (royalty in kind, RIK) or as cash (royalty in value, RIV). Alaska law states that “royalties on oil and gas shall be taken in kind unless the commissioner determines that the taking in money would be in the best interest of the state” (AS 38.05.182(a)). SB 138 also addressed the state’s ability to switch between receiving RIV and RIK (AS 38.05.180(hh)). It is assumed that a 12.5% royalty would apply to the Eileen formation and that the royalty would be taken in kind.

- Severance Tax (a.k.a. Production Tax)

This is a state tax imposed for the severing of natural resources from the land (Stermole, 2012). The State of Alaska has elected to impose a severance tax on oil and gas produced in the state. The current severance tax rate is 35% of the net value of oil and gas ([AS 43.55.011](#), SB 21). SB 138 allows tax payers to elect to pay 13% severance tax with physical gas, referred to as Tax as Gas (TAG), from January 1, 2022 onwards. This is allowed for gas that is going to be delivered to

market through a North Slope natural gas project, which is defined as a project to produce or transport natural gas from state oil or gas leases or gas only leases that include land north of 68 degrees North latitude in a gaseous state from the North Slope (AS 38.05.965(27)). Otherwise, the 13% severance tax must be paid in cash. It is assumed that hydrate production would qualify as a North Slope natural gas project, and the lessee will elect to pay the 13% severance tax as gas. The severance tax is levied against the turnover minus royalty. It is unknown whether this production would qualify for the Gross Value Reduction; as such, it has been left out of this analysis.

- Ad-valorem Tax

Ad-valorem tax is a property tax that is levied against tangible assets by the State and the North Slope Borough, with the North Slope Borough tax being credited against the State tax ([AS 43.56.010](#)). It totals 20 mills (i.e. 20 thousandths of a dollar or 2%) of the assessed value. The tangible assets include: property, plant and equipment dedicated to oil and gas exploration or production or services relating to exploration and production. Gathering lines are included; these are pipelines that transport gas and liquids from the commodity's source to a processing facility or transmission line (49 CFR § 192.3). It does not include land or transmission lines; these are pipelines that transport gas or liquids from a gathering, processing/storage facility to a processing/storage facility, large volume customer or distribution system. The gas or liquids go through a custody transfer point when moving from a gathering line, under ownership of the unit facilities, to a transmission line, under ownership of the pipeline facilities. The assessed value, i.e. replacement value, is determined as follows: The installation cost of the asset at the time of construction is adjusted to

account for inflation and changes to real cost; this is the “replication cost”. That is then depreciated to account for the time in service by multiplying it by the years of remaining service divided by the total years of field life. Note: Replacement costs can be reevaluated to account for functional obsolescence and improvements in technology; if approved by the assessor, the historic cost and timeline will be reset.

- Hazardous Substance Release Surcharge

An oil and hazardous substance release prevention and response fund within the state general fund ([AS 46.08.010](#)) was established in 1989 following the Exxon Valdez spill. Every producer of oil is required to pay a surcharge of \$0.04 per barrel of oil produced from each lease or property in the state, less any oil the ownership or right to which is exempt from taxation ([AS 43.55.300](#)). An additional surcharge of \$0.01 per barrel of oil is required if the oil and hazardous substance release prevention and response fund balance is below \$50,000,000 ([AS 43.55.201](#), [AS 43.55.221](#)). While the statute is not worded to include gas producers, it is assumed that the requirement to contribute the maximum surcharge of \$0.05 per barrel of oil equivalent to the oil and hazardous substance release prevention and response fund would apply to hydrate producers.

- Purchase Costs

This pertains to the costs incurred in the event an operator is required to purchase oil and/or gas from a third-party. These costs have not been considered in this evaluation.

Gross Margin

The gross margin is the turnover minus the turnover cost.

Total Cash Cost

Total cash cost is the sum of the operating costs, revenue expenditures and overhead costs. Only operating expenses were considered for this evaluation; this includes: lifting cost, gas processing tariffs and gas transportation tariffs. For project cash accounting, none of the capital expenditures are included in the total cash cost; these are capitalized and captured in the non-cash costs. Different costs may be expensed for determination of State and Federal taxable income; this is discussed in Section 3.7.2.

- Lifting Cost

This is the cost of producing the gas; it includes a fixed facility operational expense and a variable operating expense that fluctuates with the production rate. As described previously, the fixed facility OPEX is assumed to be 5% of the CAPEX. The variable operating expense is assumed to be \$0.15/MCF (Howe, 2004).

- Gas Processing and Transportation Tariff

A gas processing tariff must be paid for the service of processing the gas; this may include acid gas removal (if carbon dioxide exchange is employed as a recovery mechanism), compression, and or liquefaction. A gas export tariff must be paid to the pipeline operator for the service of transporting the gas to market. As discussed previously, the AGDC has anticipates a processing and transportation tariff of \$5.50 to \$9.75/MMBTU (AGDC, 2015). An average value of \$7.63/MMBTU was used in this analysis along with a gas heating value of 1.08 MMBTU/MCF was assumed (White, 2014).

Total Non-Cash Cost

The total non-cash cost is the sum of the Depletion, Depreciation and Amortization (DD&A) costs, Abandonment Accretion, and Write-offs. The

DD&A costs are defined below, and the calculation methods for project cash accounting are specified. These must be recalculated using the methods prescribed by State and Federal tax laws for the determination of State and Federal taxable income; this is discussed in Section 3.7.2.

- Resource Depletion

This is a deduction that allows the owner of an economic interest in mineral rights to recover the cost of mineral rights acquisition through federal tax deductions for depletion over the economic life of the property (Stermole, 2012). A mineral rights acquisition cost of \$2.5 million was assumed. Mineral depletion can be calculated by two methods: 1) cost depletion and 2) percentage depletion; only cost depletion is applicable to integrated producers, which are defined as petroleum producers that refine more than 75,000 barrels of crude oil per day (435 MMCFD gas equivalent) for average daily production over a year, or have retail sales of oil and gas products exceeding \$5,000,000 per year (Stermole, 2012). Given the gas production profiles and fiscal assumptions, the producer of this accumulation would qualify as an integrated producer, making cost depletion applicable. The cost depletion is calculated by dividing the volume of gas sold during the year by the volume of recoverable gas at the beginning of a year and multiplying by the adjusted basis; the adjusted basis is the cost basis minus cumulative depletion (Stermole, 2012).

- Depreciation

This is a deduction comprising, a reasonable allowance for the exhaustion, wear and tear and obsolescence of property used in a trade or business, or of property held by a tax payer for the production of income (Stermole, 2012). Tangible assets include surface and well casing, tubing, downhole equipment, wellhead, flow lines, separation

equipment, and natural gas gathering lines. As discussed previously, the CAPEX for the surface equipment required for both upgrading existing drillsites and building new drillsites was estimated using OGM (Table 3). The drilling expenditure was estimated using the averaged well lengths specified by Blake (2015) and an assumed drilling cost of \$1045 per foot (Howe, 2004). For financial accounting, all capital costs are depreciated on a unit of production basis. This method deducts costs over the estimated producing life of the asset instead of over a given period of time. This means the deductions are larger in years of high activity, smaller in years of low activity, and zero in years the asset is idle. This is the method used by petroleum companies for calculating financial net income and cash flow for shareholder reporting purposes. The annual depreciation deductions equal the asset cost multiplied by the units produced in a depreciation year divided by EUR of the asset (Stermole, 2012).

- Amortization

This is a deduction for the cost of intangible assets. For project financial accounting, the costs associated with intangible assets are depreciated on a UOP basis; therefore, none of the project costs are amortized. It is mentioned here by way of introduction, and will be discussed further in Section 3.7.2.2.

- Dismantlement, Removal and Restoration

At the end of field life, all equipment and facilities must be dismantled, removed and the environment must be restored to its original condition. Under the Statement of Financial Accounting Standard SFAS No. 143, "Accounting for Asset Retirement Obligations (AROs)", companies are required to recognize all such obligations in their

accounting practices, i.e. the company is required to set aside money to cover dismantlement, removal and restoration (DR&R) costs.

Replacement Cost Operating Profit

The replacement cost operating profit (RCOP) is the gross margin minus the total cash cost and total non-cash cost based on UOP accounting.

Replacement Cost Net Income

The replacement cost net income is the RCOP minus the state and federal corporate income tax payments. The calculation of both the state and federal corporate income tax requires a separate set of cash accounting calculations in order to determine the relevant taxable income; this is discussed in Section 3.7.2.

After Tax Cash Flow from Operations

The after-tax cash flow from operations is the replacement cost net income plus the total non-cash cost minus the DR&R cost. As discussed earlier, all equipment and facilities must be dismantled, removed and the environment must be restored to its original condition at the end of field life. It is assumed that the drilling DR&R cost will be equal to 6% of the drilling capital expenditure, and the facility DR&R cost will be equal to 10% of the facility capital expenditure (Howe, 2004). It is further assumed that the full DR&R cost will be incurred in the year following cessation of production.

After Tax Cash Flow from Project

The after-tax cash flow from project is the after-tax cash flow from operations minus capital expenditures.

Project economics are based on a discounted cash flow analysis. The annual post-tax project cash flows are estimated using prices from the year the project is sanctioned;

these values are then discounted, by applying the discount factor (Equation 1), to determine the present value.

$$\textbf{Discount Factor} = \frac{1}{(1+i)^n} \quad (1)$$

where $i = \text{discount factor}$
 $n = \text{time period}$

The mid-year accounting convention has been assumed, i.e. $n = 0.5$ for year 1, $n = 1.5$ for year 2, etc. This convention is common for projects in which investors are uncertain as to the exact timing of cash flows, or when payments/sales are occurring throughout the time period. The net present value (NPV) is the sum of the discounted cash flows. The capital expenditures are also discounted using the method above. The capital efficiency of the project is calculated by dividing the discounted capital expenditure by the discounted cash flow.

Turnover = Gross Production Volume x Gas Sales Price

Turnover Cost = Turnover – Royalty Value – Severance Tax Value – Ad Valorem Tax Value – Hazardous Substance Release Surcharge Value

Royalty Value = Royalty Volume x Gas Sales Price

Royalty Volume = Gross Production Volume x Royalty Rate

Severance Tax Value = Severance Tax as Gas x Gas Sales Price

Severance Tax as Gas = (Gross Production Volume – Royalty Volume) x Severance Tax Rate

Ad Valorem Tax = Assessed Value of Tangible Property x Ad Valorem Tax Rate

Assessed Value of Tangible Property = Replication Cost x Years of Service Remaining / Total Years of Field Life

Replication Cost = Original Installation Cost * (1+i)ⁿ

Hazardous Substance Release Value = (Gross Production Volume – Royalty Volume) x Barrel of Oil Equivalent Factor x Surcharge Rate

Gross Margin = Turnover – Turnover Cost

Total Cash Cost = Operating Expenses + Revenue Expenses + Overhead Costs

Operating Expenses = Fixed Lifting Cost + Variable Lifting Cost + Gas Processing Tariff + Gas Transportation Tariff

Total Non-Cash Cost = Depreciation Cost (based on Units of Production) + Depletion Cost + Amortization Cost + Dismantlement, Removal & Restoration Provision

Depreciation Cost (based on Units of Production) = Cost Basis x Gross Production Volume Produced / Estimated Ultimate Recovery Volume

Cost Basis = Capital Expenditure + Drilling Expenditure

Depletion Cost = Adjusted Cost Basis x Gross Production Volume / Estimated Volume Recoverable at Beginning of the Year

Adjusted Cost Basis = Cost Basis +/- Adjustments – Cumulative Depletion

Cost Basis = Cost of Mineral Rights Acquisition + Lease Bonus

Amortization Cost is not applicable for here.

Replacement Cost Operating Profit = Gross Margin – Total Cash Cost – Total Non-Cash Cost

Replacement Cost Net Income = Replacement Cost Operating Profit – State Tax Payment – Federal Tax Payment

After Tax Cash Flow From Operations = Replacement Cost Net Income + Total Non-Cash Cost – Dismantlement, Removal & Restoration Payment (last year)

After Tax Cash Flow from Project = After Tax Cash Flow From Operations – Capital Expenses

Figure 42 Illustration of Cash Accounting Method

3.7.2 Corporate Income Tax Calculations

Separate cash accounting calculations must be completed, in parallel to the project cash accounting, in order to determine the taxes payable to both the state and federal government. These accounting calculations differ in both the measurement of business income and the handling of capital expenditure. In order to understand how such differences came to be, some background information is provided below.

When companies operate in multiple states or countries, the income that should be subject to tax in each state in which it is doing business must be determined. There are two schools of thought: 1) separate accounting systems should be used to measure the income and expenses associated with activities in each state, and 2) the total business income should be apportioned among the states in which the company operates. There are inherent inaccuracies and challenges with both separate accounting and apportionment. In the United States, the National Conference of Commissioners on the Uniform State Laws (NCCUSL), previously named the Uniform Law Commission (ULC), researches, drafts and proposes state laws, also referred to as uniform acts, in areas of state law where uniformity is desirable. States can adopt the uniform act as proposed, make substantial changes when adopting the uniform act, or choose to develop their own laws. One such act is the Uniform Division of Income for Tax Purposes Act (UDITPA) was drafted with the intent to assure that tax-payers are not taxed on more than their net income. UDITPA calls for all business income to be apportioned to the state based on amount of property, production and sales in Alaska relative to the rest of the world. UDITPA was drafted by the NCCUSL and adopted by the American Bar Association in 1957 and later amended in 1966. Alaska adopted UDITPA in 1959 and joined the Multistate Tax Commission (MTC) in 1971.

When computing taxable income, deductions from the gross business income are allowed for “all the ordinary and necessary expenses paid or incurred during the taxable year in carrying on any trade or business”, in other words operating expenses

([26 CFR § 162](#)). In general, these do not include capital expenditures, which are defined as amounts that “add to the value, or substantially prolong the useful life, of property owned by the taxpayer, such as plant and equipment, or ... [that] adapt property to a new or different use” ([26 CFR § 1.263\(a\)-1](#)). Additional deductions are allowed for the “reasonable allowance for the exhaustion, wear and tear (including a reasonable allowance for obsolescence) -- (1) of property either used in a trade or business, or (2) of property held for the production of income”, otherwise referred to as depreciation deductions ([26 CFR § 167](#)). Most types of tangible property, such as buildings and equipment, and some intangible assets, such as patents and copyrights, are depreciable; however, the asset must have a limited useful life. The federal tax depreciation policy has changed a number of times. Early versions of the tax code granted liberal taxpayer discretion in the choice of depreciable lives, asset salvage values and depreciation accounting methods; this placed a significant oversight burden on both the Bureau of Internal Revenue and taxpayers to determine the reasonableness of deductions taken (Brazell et. al, 1989). This led to the issuance of the Asset Depreciation Range (ADR) system, for tangible assets placed in service after 1970. Businesses were granted greater flexibility in the depreciable life of their assets, ranging from 20% below to 20% above the IRS’s established useful life. However, the ADR system did not resolve all the problems it was intended to address. This, in addition to the country’s need for economic stimulation in the late 1980s, led to another round of tax reform. The ADR system was replaced by the Accelerated Cost Recovery System (ARCS) in 1981 in order to provide a less complicated way to determine depreciation and to provide incentive for capital investment. ARCS effectively lowered tax rate on tangible depreciable investments. However, ARCS allowances did not reflect the economic loss in value of assets due to wear and tear; the depreciation deductions proved to be too aggressive, and led to increased “tax shelter” activity (Brazell et al., 1989). Congress adopted the Modified Accelerated Cost Recovery System (MACRS) in 1986, which grants less aggressive depreciation

deductions and neglects the salvage value. Prior to 1981, the State of Alaska elected to adopt the federal code for the calculation of taxable income. However, the problems with ARCS were recognized early by the State of Alaska, and legislation was passed to require continued use of the pre-1981 version of the federal code ([AS 43.20.072](#)). This has not been changed, despite the enactment of the less aggressive MACRS depreciation at the federal level.

3.7.2.1 State Corporate Income Tax

Alaska's tax rates vary from 1% to 9.4% depending on the corporate taxable income (Table 4).

Firstly, Alaska requires the business income of a taxpayer engaged in the production of oil or gas from a lease or property in this state to be apportioned to this state based on amount of property, production and sales in Alaska relative to the rest of the world ([AS 43.20.072](#); Ryherd, 2014); this is in accordance with the UDITPA theory and the Multistate Tax Compact (AS 43.19.010). That means that the corporate income taxes will not only depend on the project expenses and income, but also upon which company the project is operated by. If the producing company is an entity operating within Alaska's jurisdiction only, then the corporate income tax is applied to the project's booked income.

However, if the producing company is a subsidiary of a multinational corporation the corporate income tax is applied to the income apportioned to Alaska. The ratios of profitability vary significantly both between companies and over time. In order to complete a first pass evaluation of the economic feasibility of hydrate production, there is no option but to consider it as a stand-alone project. This, in line with the UDITPA theory, should give consistent results over the life of the project.

Secondly, the taxable income must be calculated with all capital expenditures, including intangible drilling costs, being depreciated on the basis of Internal Revenue Code (26 CFR § 167) as that section read on June 30, 1981 ([AS 43.20.072\(b\)\(4\)](#)).

| If taxable income is: | | | |
|-----------------------|----------------|----------------|----------------------|
| Over - | But not over - | Tax is - | Of the amount over - |
| \$0 | \$10,000 | 1% | \$0 |
| \$10,000 | \$20,000 | \$100 + 2% | \$10,000 |
| \$20,000 | \$30,000 | \$300 + 3% | \$20,000 |
| \$30,000 | \$40,000 | \$600 + 4% | \$30,000 |
| \$40,000 | \$50,000 | \$1,000 + 5% | \$40,000 |
| \$50,000 | \$60,000 | \$1,500 + 6% | \$50,000 |
| \$60,000 | \$70,000 | \$2,100 + 7% | \$60,000 |
| \$70,000 | \$80,000 | \$2,800 + 8% | \$70,000 |
| \$80,000 | \$90,000 | \$3,600 + 9% | \$80,000 |
| \$90,000 | - - - - - | \$4,500 + 9.4% | \$90,000 |

Table 4 Alaska State Corporate Tax Rate Schedule
(adapted from [AS 43.20.011](#))

This does not change the total amount of depreciation that may be taken over the life of an asset, but it does change the timing of the deductions. Depreciation is less accelerated under the 1981 version of the federal tax code. This applies to all property that is included in the depreciation on the federal tax return, not just the property in Alaska. For the purposes of this evaluation, the Asset Guideline Class 46 Pipeline Transportation is assumed to apply; this class has an Asset Guideline Period of 22 years. While the ADR system allows the taxpayer 20% leeway in the determination of the asset life, i.e. a lower limit of 17.5 years and an upper limit of 26.5 years, the guideline value has been used. The most front-end loaded method for calculation of depreciation, double-declining balance, was applied along with the mid-year convention.

3.7.2.2 Federal Corporate Income Tax

Federal tax rates vary from 15% to 35% depending on the corporate taxable income (Table 5).

| If taxable income is: | | | |
|-----------------------|----------------|-------------------|----------------------|
| Over - | But not over - | Tax is - | Of the amount over - |
| \$0 | \$50,000 | 15% | \$0 |
| \$50,000 | \$75,000 | \$7,500 + 25% | \$50,000 |
| \$75,000 | \$100,000 | \$13,750 + 34% | \$75,000 |
| \$100,000 | \$335,000 | \$22,250 + 39% | \$100,000 |
| \$335,000 | \$10,000,000 | \$113,900 + 34% | \$335,000 |
| \$10,000,000 | \$15,000,000 | \$3,400,000 + 35% | \$10,000,000 |
| \$15,000,000 | \$18,333,333 | \$5,150,000 + 38% | \$15,000,000 |
| \$18,333,333 | ----- | 35% | \$0 |

Table 5 Federal Corporate Tax Rate Schedule
(adapted from IRS Instructions for Form 1120 U.S. Corporation Income Tax Return)

A large portion of drilling expenditure is intangible (i.e. rig time) while the rest is tangible (i.e. casing, tubing, wellhead, etc.). It is assumed that 80% of drilling costs are intangible and 20% are tangible. For determination of federal taxable income, 70% of the intangible drilling costs can be “expensed”, i.e. deducted in full in the year incurred, in addition to the operating expenses, defined earlier; the remaining 30% can be amortized straight line over a five year or 60 month period beginning in the month the costs are paid or started to be incurred (Stermole, 2012). The tangible capital expenditures are then depreciated using the MACRS depreciation method (Stermole, 2012); a depreciable life of 7 years has been assumed. This is based on the assumption, supported by the production forecasts in Section 3.4 and fiscal assumptions provided in Section 3.7.1, that the producer would qualify as an integrated producer.

3.8 Economic Indicators

Investors, both individuals and corporations, always have a choice of competing investment vehicles to grow their money. Economic indicators are used to systematically evaluate the merits of each project. No one indicator will provide a complete understanding of the profitability or relative risk in a project. The key indicators are: NPV, Internal Rate of Return (IRR), and Payback Period.

Net Present Value is the difference between the present value of cash inflows and the present value of cash outflows. It is one of the most reliable economic indicators because it accounts for the time value of money. In order to be considered economically feasible, the NPV must be greater than zero; the greater the NPV, the more economically favorable the project is.

$$\text{Net Present Value} = \sum_{n=0}^N \frac{A_n}{(1+i)^n} \quad (2)$$

where i = discount factor

n = time period

N = total number of time periods, i.e. service life of the project

A_n = net cash flow in period n

Internal Rate of Return is the discount rate that would be required to make the NPV of all cash flows from a particular project equal to zero. It provides a measure of the yearly compound rate that a firm or individuals stand to gain from the investment. The larger the IRR, the more economically favorable the project is. Investors often specify a minimum acceptable rate of return (MARR); projects are required to have a positive NPV when the MARR is used as the discount rate in order to be sanctioned.

Discounted Payback Period is the time in which the initial cash outflow of an investment is expected to be recovered from the earnings generated by the project, taking the time value of money into account. It provides a measure of the risk in a project; cash flows that occur further in the future are more uncertain than those nearer term. For investors with liquidity problems, it allows projects to be ranked by how quickly they would return money. The shorter the payback period, the more

economically favorable the project is. This is by far the simplest appraisal technique. However, it does not take into account cash flows after the payback period, i.e. the long term profitability of the project.

$$\textbf{Discounted Payback Period} = A + \frac{B}{C} \quad (3)$$

where A = last period with a negative discounted cumulative cash flow

B = abs. value of discounted cum. cash flow at end of period A

C = discounted cash flow during the period after A

CHAPTER 4 RESULTS AND DISCUSSION

Before evaluating the results of the economic analysis of the various production scenarios, a general review of the key factors impacting the economics is warranted. The cash flows associated with one production scenario will also be reviewed for illustrative purposes. Following that, the economic indicators for each of the six production scenarios will be discussed.

4.1 Regional Production Forecasts

As with any project, the timing of cash outflows and inflows is critical in understanding the investment risk. Taking into account the time value of money, anything that accelerates production, and therefore turnover, will be more economically competitive. A review of the regional production profiles reveals useful insight into how reservoir characteristics, namely initial hydrate saturation, and development decisions, such as well spacing and design, will affect the timing of gas production.

Reservoirs with low initial hydrate saturation recover between 3.8 and 5.4 TCF following 50 years of production (Figure 43). The higher EUR is achieved if wells are drilled at 160 acre spacing; however, this additional gas production comes at the price of drilling twice as many wells. The same EUR is achieved with horizontal and vertical wells at 160 acre spacing; however, horizontal wells will produce gas significantly faster than vertical wells. As discussed previously, the reservoir modelling that has formed the basis of this evaluation used a vertical well length of 2300 feet and a horizontal well length of 4300 feet (Blake, 2015). The question that must be raised is whether the accelerated production seen with horizontal well development in Case B outweighs doubling the drilling cost when compared to vertical well development in Case C.

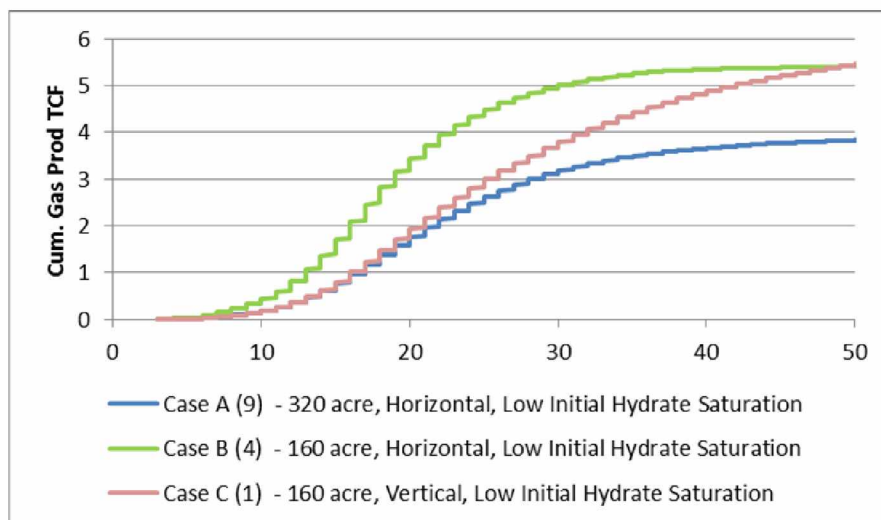


Figure 43 Regional Production Forecasts for Low Initial Hydrate Saturation (51%)
Note: Numbers in parentheses refer to case study numbers of Blake (2015).

Reservoirs with high initial hydrate saturation recover between 3.6 and 4.5 TCF following 50 years of production (Figure 44). The cumulative gas production for all three development scenarios is lower given high initial hydrate saturation; this may be counterintuitive, especially given that on an individual well basis, producing from reservoirs with higher initial hydrate saturation will produce more cumulative gas than reservoirs with lower initial hydrate saturation. However, it is simply a manifestation of the fact that wells producing from reservoirs with high initial hydrate saturation reach peak production later and the peak production rates are lower. When a drilling schedule is applied, and the well production rates are staggered over time, the wells drilled later in field life do not reach their full potential given a field life of 50 years. Beyond that, similar questions arise when reviewing the cumulative production profiles of reservoirs with high initial hydrate saturation as those with lower initial hydrate saturation. Again, the 160 acre spacing development leads to a higher overall EUR when compared to 320 acre spacing development, but the benefit may be outweighed by the higher drilling and capital expenditure. There is a difference in the comparison of vertical and horizontal wells at 160 acre spacing. The vertical well

development actually outperforms the horizontal well development in terms of cumulative gas production and the difference in timing of gas production between 10 and 30 years is less pronounced. This comparable timing of gas production may make the lower cost vertical wells more competitive than the horizontal wells.

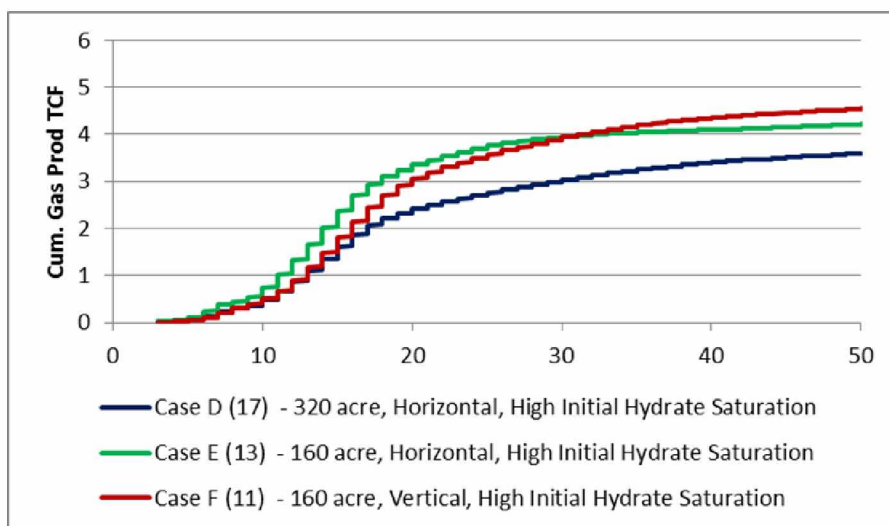


Figure 44 Regional Production Forecasts for High Initial Hydrate Saturation (75%)
Note: Numbers in parentheses refer to case study numbers of Blake (2015).

4.2 Fiscal Environment

As with any oil and gas project, the sales price of the commodity will be a key factor in deciding whether the project is economic or not. The end point gas price must be low enough to compete with alternative gas sources, such as conventional gas, coal bed methane, and shale gas, but high enough to allow the producer to recoup their investment in a reasonable time frame and earn a profit. The end point gas price comprises: the tariff, local distribution charges and the base gas price. Tariffs provide a means for the operator to recover the capital expenditure for the gas processing plant and pipeline. The tariffs that will apply to the development of ANS hydrates are highly dependent on how conventional ANS gas is commercialized. Of the two competing projects, the Alaska LNG project is expected to require significantly higher capital expenditure due to the level of gas processing (liquefaction) required to

sell to the Asian markets; the ASAP project on the other hand requires less capital as it is targeting a typical utility gas specification. The ASAP project, being a state owned enterprise, publishes its cost estimates in an annual report to the Governor as well as in press releases. The latest cost estimated tariff averaged \$7.63/MMBTU; this is based on an estimated capital cost of \$10 billion with a commercial operation date of 2021 (AGDC, 2015). The Alaska LNG project, on the other hand, is a privately owned enterprise and the tariffs and estimated gas prices are proprietary information. However, the State of Alaska hired a third-party consultant, Black & Veatch, to evaluate the economics of the Alaska LNG project in November 2013 based on the cost data made available to the public. The estimated tariff came to \$13.12/MMBTU; based on an estimated capital cost of \$45 billion with a commercial operation date around 2023-24 (Black & Veatch, 2013). Note that this may be conservative given that the upper range of the estimate is \$65 billion.

The AGDC end consumer gas prices were used in this economic evaluation of hydrate production; however, it should be noted that this is likely a conservative value for two reasons. Firstly, if the Alaska LNG is the project that goes forward, the tariffs may be double for the reasons discussed above. Secondly, the AGDC values are based on the assumption that there is sufficient demand (e.g. local, industrial, export, etc.) to maintain a throughput of 500 MMCFD. The local gas demand is approximately 250 MMCFD total (Baker, 2015). That is currently being met by the gas from Cook Inlet, meaning ANS gas, whether it be conventional or hydrate, would need to be cost competitive. That leaves 250 MMCFD or more that would need to be exported.

4.3 Cash Flow Illustration

The cash flow calculations for one production scenario over a 50 year life will be discussed in detail to illustrate the process. Case B is the production scenario that assumes the reservoir has low average initial hydrate saturation (51%) and it is developed using horizontal wells at 160 acre spacing. The economic calculations were

run using an arbitrary gas price of \$22.00/MMBTU (2015\$) which translates to \$33.85/MMBTU in 2020 at 9% inflation. As discussed in Section 4.1, initial reviews of the production profiles raised the question of whether the additional drilling cost will be outweighed by the acceleration of gas production. The cash flows in Figure 47 clearly illustrates that, while the drilling does present a sizable portion of the capital expenditure that must be funded by the investor, it is dwarfed by the other expenses incurred by the project.

The largest single expense is the processing and transportation tariff during peak production (Figure 45). While the investor recovers these costs, by passing them on to the customer through increased end user gas prices, this is a key driver in the economic feasibility of the project. In order to be economic, the end user prices must be competitive with the alternative gas sources in the marketplace. The results of a gas price sensitivity analysis will be discussed in Section 4.4.

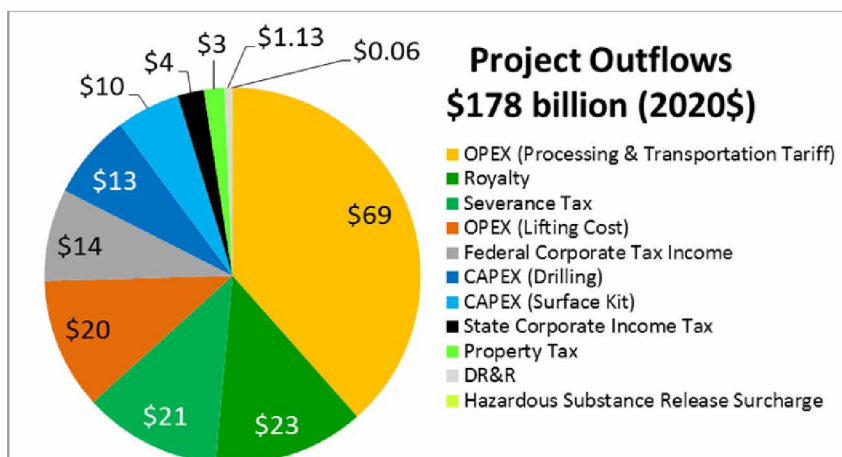


Figure 45 Project Cash Outflows over Life of Project (2020\$)

When viewed as a whole, the government take totals \$66 billion, making it the next largest portion of the project outflows (Figure 46). The largest of these is the royalty and severance tax, both of which are proportional to the gas production rates; the corporate income taxes follow, with the federal income taxes being the larger of the

two; the property tax and hazardous substance release charge form a relatively small proportion of the government take.

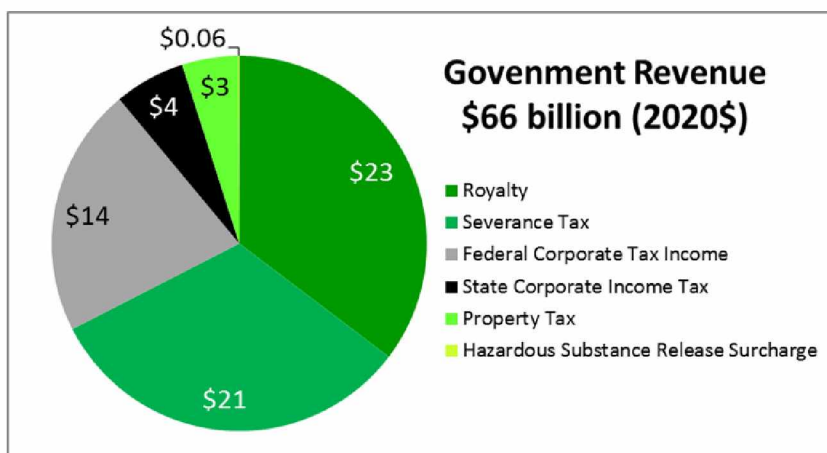


Figure 46 Government Revenue over Life of Project (2020\$)

The after tax cash flow from the project (2020\$) become positive in 2024 following the drilling phase associated with Stage 3 of the proposed field development plan: drilling 98 wells from the 14 drillsites that are located over the Eileen C sand hydrate accumulation, producing into the existing flowlines and processing the fluids at the existing separation facilities (Figure 47, Figure 48). This is attributable to relatively minor surface modifications that would need to be made as compared to those that would be required for full field development. A medium scale, long term production trial may be economic provided that there is a local demand for that gas resource. However, the net present value for full field development does not become positive until 2037.

While the type well production profiles were based on a 50 year life, the project end of life is defined by the time at which the NPV reaches its maximum value. That point is reached in approximately 2053 in this scenario, when the NPV is \$2.8 billion, the IRR is 12%, and the EUR is 5.2 TCF giving a recovery factor of 49%. While the field is still technically capable of producing a significant volume of gas in the following years, the operational expenses are expected to outweigh the turnover.

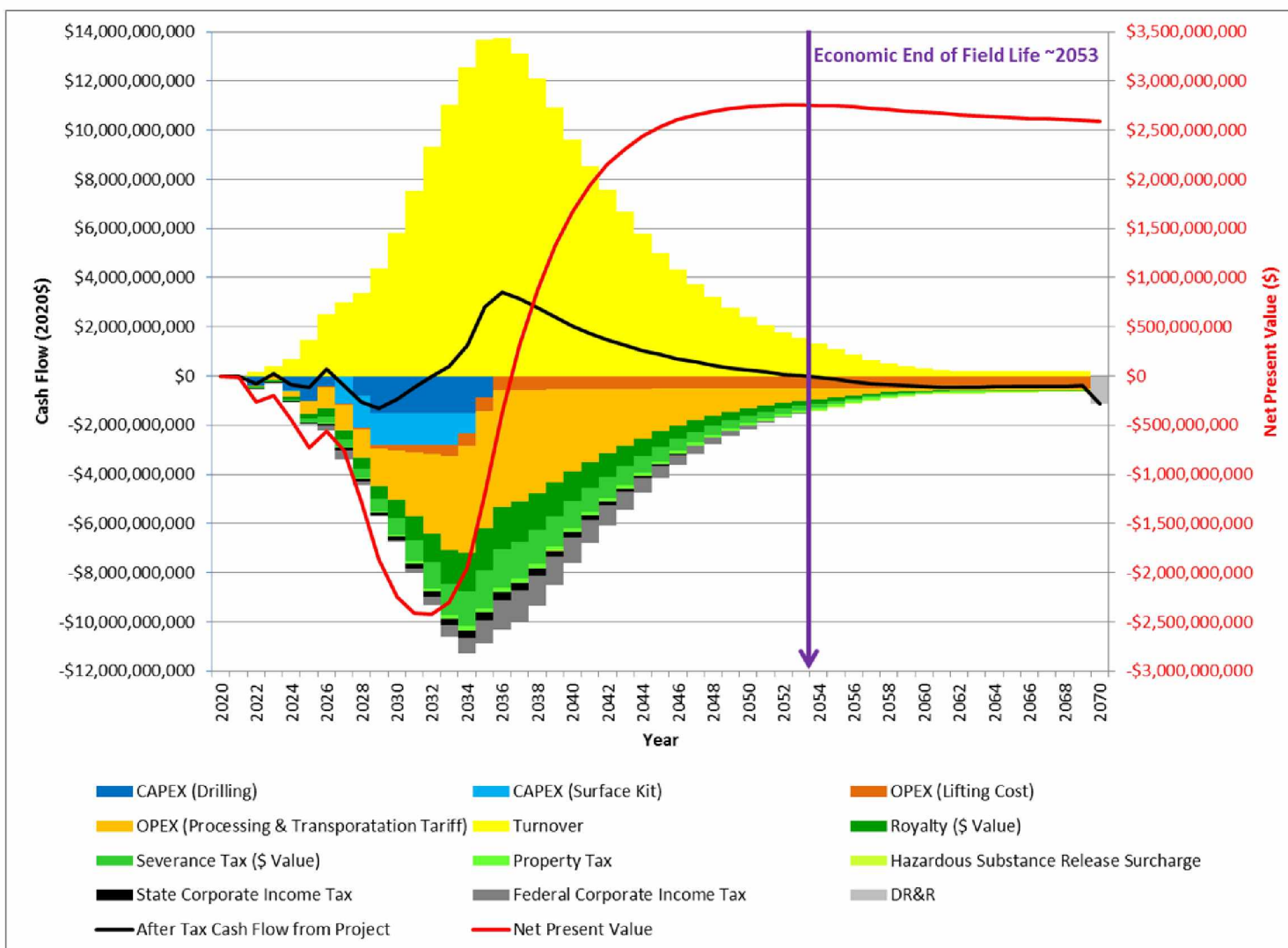


Figure 47 Cash Flow and NPV vs. Time for Case B (Gas Price \$22/MMBTU) - 50 Years

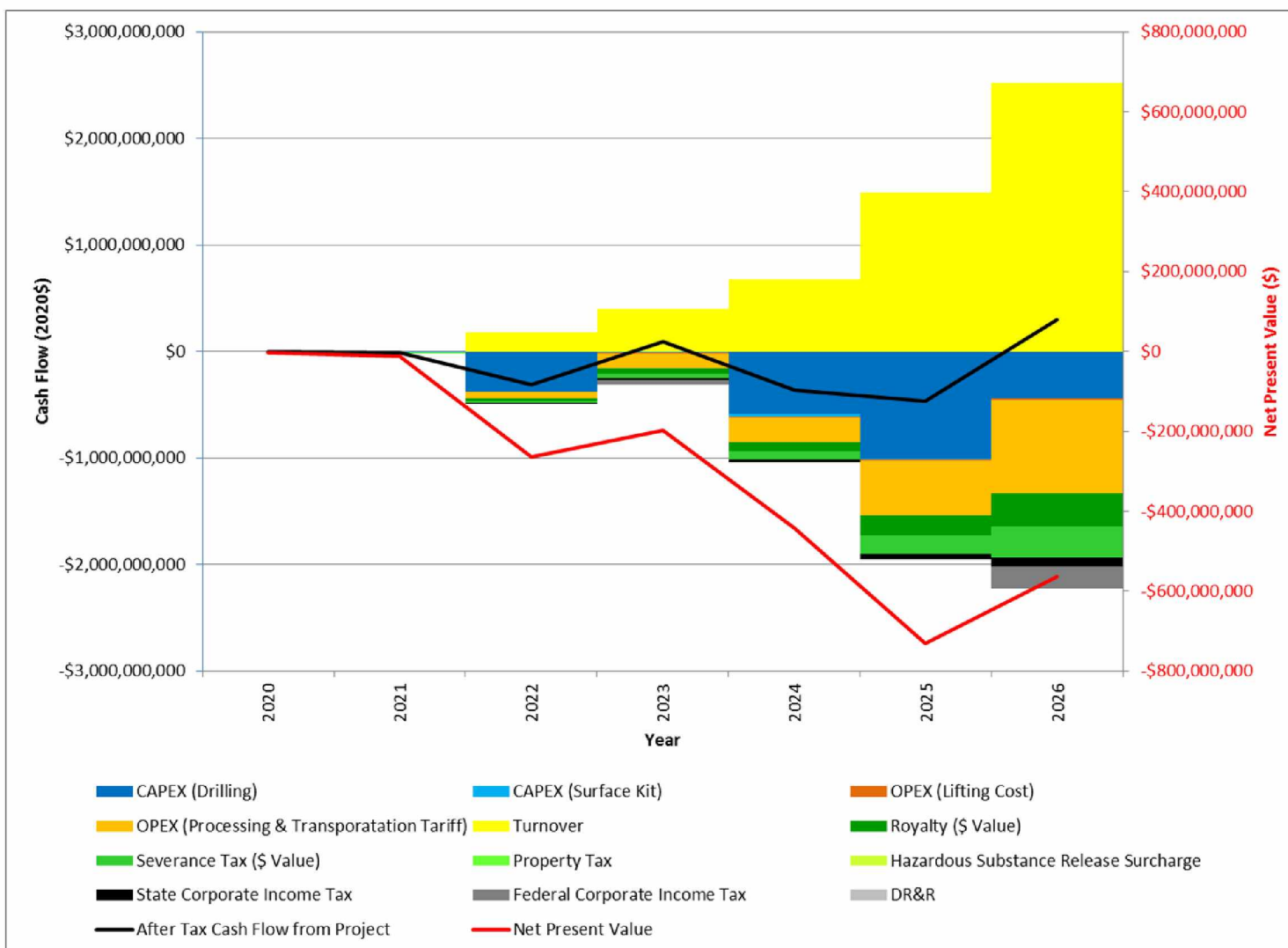


Figure 48 Cash Flow and NPV vs. Time for Case B (Gas Price \$22/MMBTU) - 7 Years

4.4 Economic Evaluation

The economics of any hydrocarbon development project at the pre-appraise stage can be highly variable due to uncertainties in geology, reservoir characteristics, and the fiscal environment. With gas hydrate developments there is added uncertainty due to the lack of long term well productivity data. The potential value of the resource must be quantified, if roughly, in order to justify investment in long term pilot projects.

The primary purpose of this study was to estimate the price of natural gas that may lead to economically viable production from ANS gas hydrates, which have been identified as the most promising hydrate accumulations (Ruppel, 2011). There are a variety of definitions for economic viability. One of the most common is defining a MARR - the lowest ROR at which a company will consider investing. It is a function of the traditional inflation-free rate of interest for risk free loans, the expected rate of inflation, the anticipated change in the rate of inflation, if any, over the life of the investment, the risk of defaulting on a loan, and the risk profile of a particular venture (Lang, et al., 1993). Each investor will have a different MARR depending on their financial situation and understanding of the risk in a particular venture. For evaluation purposes, a MARR of 20% has been assumed. For two projects that yield the same IRR, the one with the more positive NPV is preferred as it yields the greatest value to the investor.

The maximum NPV was calculated for each production scenario at a range of gas prices, as were the associated IRR and EUR (Figure 49 and Figure 50). The gas prices listed below are in 2015 dollars and have been inflated to 2020 dollars at a 9% inflation rate, as have all the other costs. All economic evaluations started at a gas price of \$38/MMBTU, and the gas price was reduced incrementally from there. As the gas price was reduced, the maximum NPV reduced, along with the associated IRR and EUR, and time to the economic end of field life shortened. The evaluation continued

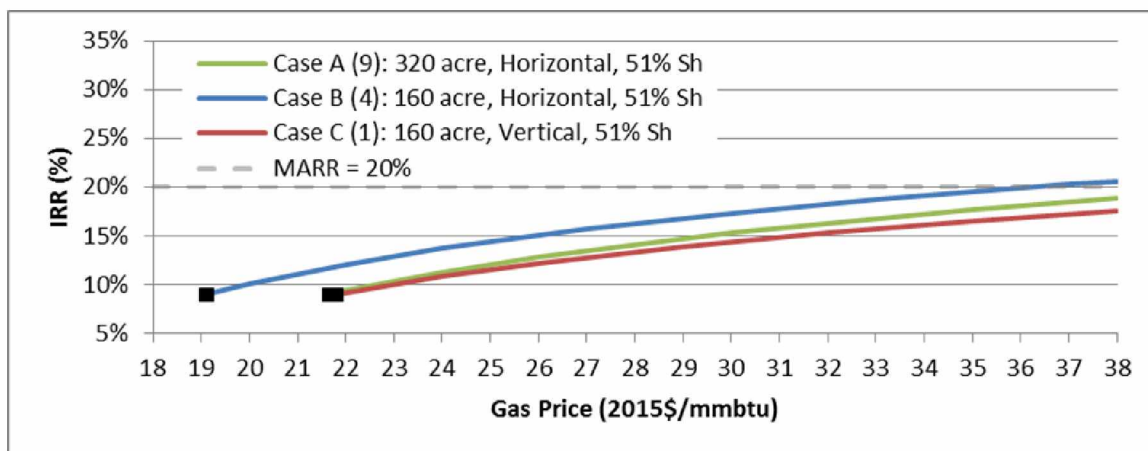
until a point at which either the development as a whole was uneconomic (NPV was less than zero throughout the field life), or the economics for a full field development were unfavorable in comparison to a smaller scale development, described in Section 3.3.4 (NPV peaked following the drilling phase associated with Stage 3 of the proposed field development plan). For the former scenarios, the gas price leading to a breakeven point (NPV = \$0) are reported using a black marker (see Case A, B, and C in Figure 49 and Case F in Figure 50). For the latter scenarios, the NPV, associated IRR and EUR reached in year 7 of the limited initial development, described in Section 3.3.3, are reported using a black marker (see Case E and F in Figure 50). The discussion that follows discusses the economic viability of the full field development scenarios only.

If the reservoir has low initial hydrate saturation, then \$36.18/MMBTU is the minimum gas price that would allow economically viable production of natural gas hydrates. This would be dependent on the field being developed with horizontal wells at 160 acre spacing, and would generate an NPV of \$15.4 billion with an IRR of 20% (Case B, Figure 49). The project would end following 37 years of production in 2057 having recovered 50% of the OGIP (5.3 TCF). The other development options will not meet the MARR even if gas prices climb as high as \$38.00/MMBTU, and the NPV of these scenarios will always be less than if the field was developed with horizontal wells at 160 acre spacing.

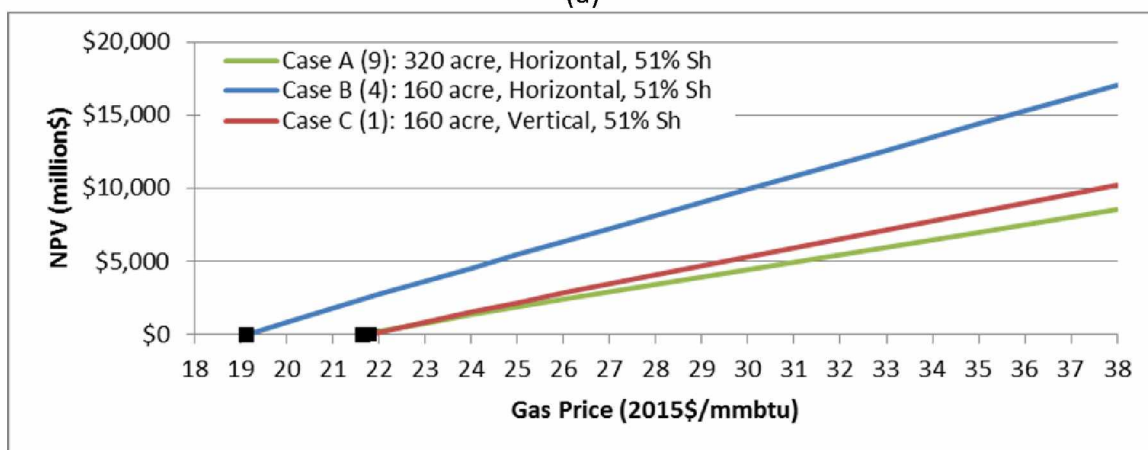
If the reservoir has high initial hydrate saturation, the viability price estimate would decrease to \$29.83/MMBTU. This would be dependent on the field being developed with horizontal wells at 320 acre spacing, and would generate an NPV of \$927 million with an IRR of 20% (Case D, Figure 50). The project would end following 28 years of production in 2048 having recovered 18% of the OGIP (3.0 TCF). The alternative development options, horizontal and vertical wells at 160 acre spacing, will become economic at the slightly higher gas prices of \$30.57/MMBTU (Case F, Figure 50) and \$32.06/MMBTU (Case E, Figure 50), respectively. The gas prices above are not

significantly different, showing that the choice of development scenario does not impact the project economics significantly given a reservoir with high average initial hydrate saturation.

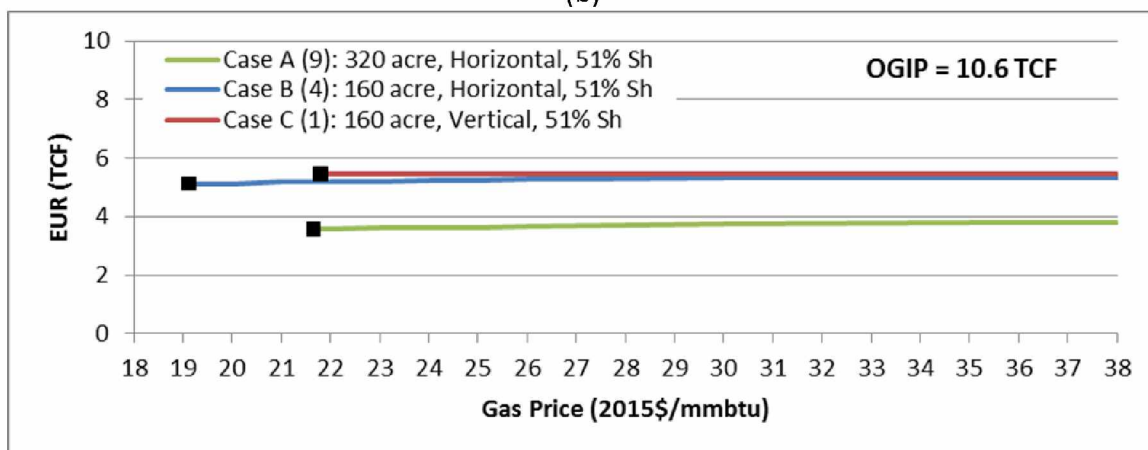
In order for gas from hydrates to compete in the marketplace, the price must be competitive with alternative fuel sources. For example, in Fairbanks natural gas from hydrates would have to compete with alternative fuel sources such as conventional gas, estimated to cost \$11.50 to \$14.00/MMBTU by the AGDC (2015), and heating fuel, which has an average price of \$22.59/MMBTU. [The heating fuel price estimate was based on the average heating fuel #1 price of \$3.05/gallon and an average heating value of 0.135 MMBTU/gallon (Walker, 2015).]



(a)

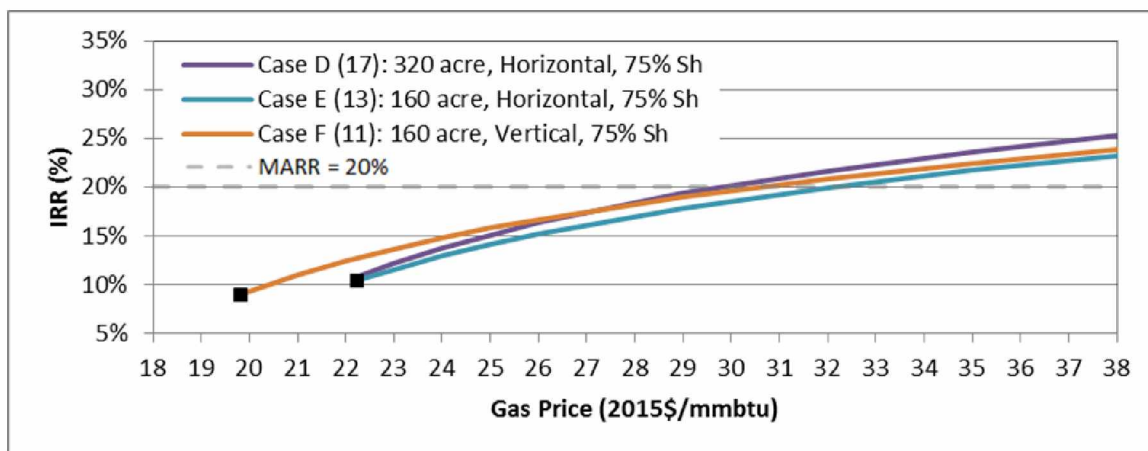


(b)

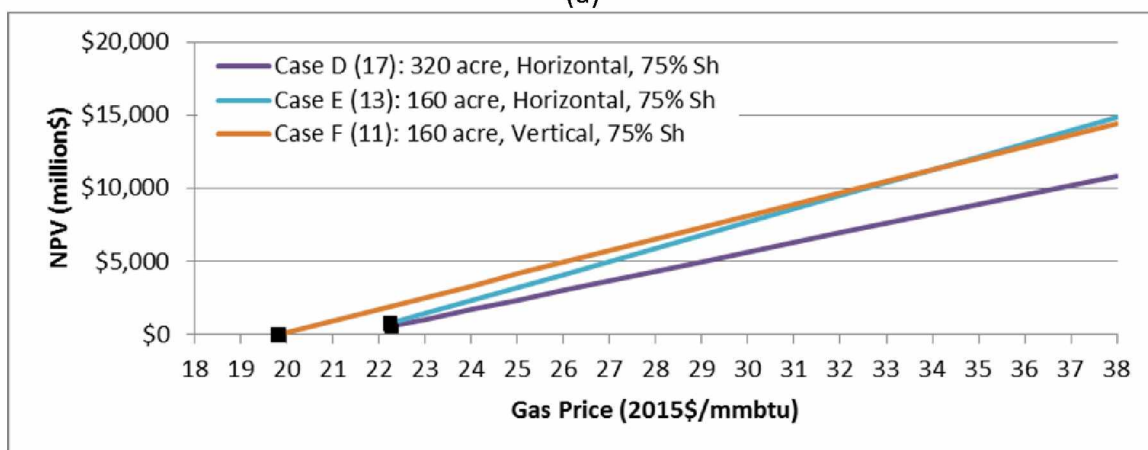


(c)

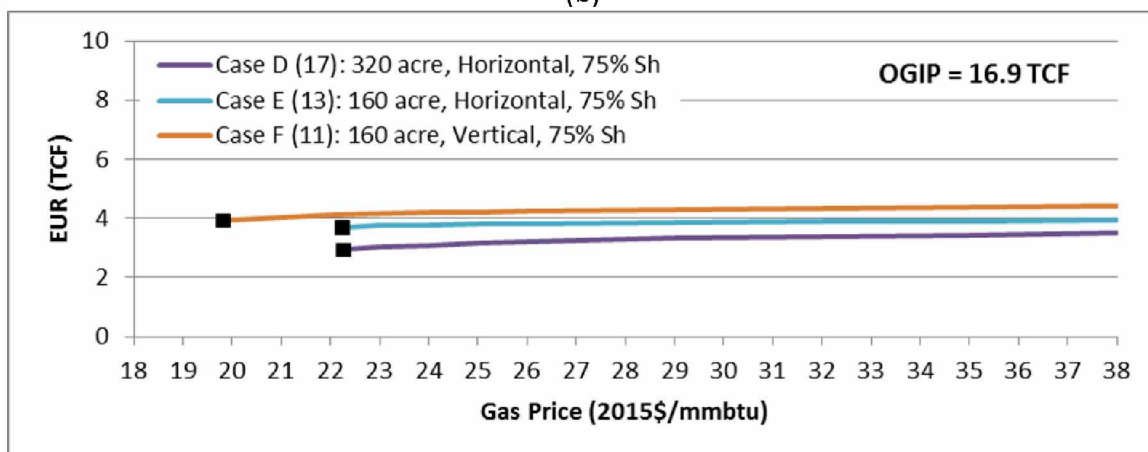
Figure 49 IRR, NPV and EUR vs. Gas Price at End of Field Life - Low S_{hi}
Note: Numbers in parentheses refer to case study numbers of Blake (2015).



(a)



(b)



(c)

Figure 50 IRR, NPV and EUR vs. Gas Price at End of Field Life - High S_{hi}
Note: Numbers in parentheses refer to case study numbers of Blake (2015).

CHAPTER 5 CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

In order for gas hydrates to be considered a technically viable source of natural gas, scientific and exploration work must continue to the next logical step: long term well tests. These will be critical in the validation of reservoir and well production modelling efforts, whose production forecasts will form the foundation of a regional production project.

The hypothetical development scenarios evaluated in this study bracketed the volume of gas that could be technically and economically recoverable from the C sands of the Eileen gas hydrate accumulation. If a reservoir has high average initial hydrate saturation (75%), between 3.6 and 4.5 TCF may be technically recoverable from an estimated 16.9 TCF OGIP following 50 years of production. That range is increased if the reservoir has low average initial hydrate saturation (51%); between 3.8 and 5.5 TCF may be recoverable from an estimated 10.6 TCF OGIP following 50 years of production. The volume that is economically recoverable is highly dependent on how the field is developed. A field that has higher vertical heterogeneity and corresponding lower average initial hydrate saturation is most economically produced using horizontal wells at 160 acre spacing; the acceleration of gas production outweighs the increased drilling costs associated with the longer wells and tighter well spacing. However, the choice of development scenario does not impact the project economics significantly given a field that has lower vertical heterogeneity and corresponding higher average initial hydrate saturation; all three development scenarios (horizontal wells at 320 acre spacing, horizontal wells at 160 acre spacing and vertical wells at 160 acre spacing) are economic given a minimum gas price of \$32.57/MMBTU, with development using horizontal wells at 320 acre spacing being marginally more economic than the alternatives.

The minimum gas price that would allow economic production of ANS gas hydrates is \$29.83 to \$36.18/MMBTU. The lower value could be withstood given a reservoir with high average initial hydrate saturation developed with horizontal wells at 320 acre spacing. The higher value corresponds to a reservoir with low average initial hydrate saturation developed with horizontal wells at 160 acre spacing.

As with all economic analyses, the results presented here are highly dependent on fiscal assumptions that have been made in the development of the economic model. By applying the most common royalties, the current tax laws applicable to conventional gas, and most recent tariff estimates, it is clear that conventional ANS gas production is more economically attractive than that from ANS gas hydrates when targeting sale in the interior and southern parts of Alaska and international markets. However, the economics of ANS hydrate development could be improved in two ways. The State of Alaska could decide that the lease agreements and laws written for conventional gas are not applicable to hydrate gas production; if that is the case, enabling legislation could be passed in order to incentivize investment. Alternatively, the hydrate resource could be viewed as a local gas resource, given a large enough demand; this would significantly reduce the capital expenditure associated with the project, in turn reducing the gas processing and transportation tariffs.

5.2 Recommendations for Future Work

This evaluation focused solely on hydrate production through depressurization. An alternative production scenario, carbon dioxide exchange with methane, was tested with favorable results at the Ignik Sikumi Hydrate well on PBU's L Pad. Provided that conventional ANS gas is commercialized through one of the two ongoing projects, AK LNG and ASAP, a waste stream of carbon dioxide will be generated on the slope that could be put to a number of uses, one of which is hydrate production. Reservoir modelling studies are underway at PNNL with the goal of generating long-term methane production and carbon dioxide sequestration profiles. A similar

economic analysis to this could be completed to estimate the potential methane recovery and carbon dioxide sequestration volumes over time.

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NOMENCLATURE

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| AAPG | American Association of Petroleum Geologists |
| AGDC | Alaska Gasline Development Corporation |
| AGIA | Alaska Gasline Inducement Act |
| AK LNG | Alaska Liquefied Natural Gas |
| ANS | Alaska North Slope |
| AS | Alaska Statute |
| ASAP | Alaska Stand Alone Pipeline |
| BCFD | Billion standard cubic feet per day |
| BIBPF | Base of the ice-bearing permafrost |
| BPXA | BP Exploration (Alaska), Inc |
| CAPEX | Capital expenses |
| CFD | Standard cubic feet per day |
| CFR | Code of Federal Regulations |
| CPAI | ConocoPhillips Alaska, Inc |
| CPF | Central processing facility |
| DD&A | Depletion, Depreciation and Amortization |
| DNR | Department of Natural Resources |
| DOE | Department of Energy |
| DR&R | Dismantlement, Removal and Restoration |
| EOR | Enhanced oil recovery |
| EUR | Estimated ultimate recovery |
| GCF | Gas Conditioning Facility |
| GTP | Gas Treatment Plant |
| HVAC | Heating, ventilating, and air conditioning |
| IRR | Internal Rate of Return |
| JOGMEC | Japan Oil, Gas, and Metals National Corporation |
| KRU | Kuparuk River Unit |

| | |
|----------|---|
| MARR | Minimum Acceptable Rate of Return |
| MBD | Thousand barrels per day |
| MCFD | Thousand standard cubic feet per day |
| MD | Measured depth |
| MMBTU | Million British thermal units |
| MMCFD | Million standard cubic feet per day |
| MPU | Milne Point Unit |
| MTA | Million tonne per annum |
| NETL | National Energy Technology Laboratory |
| NGL | Natural gas liquid |
| NPV | Net Present Value |
| OGIP | Original gas in place |
| OGM | Oil & Gas Manager |
| OPEX | Operating expenses |
| PBU | Prudhoe Bay Unit |
| PNNL | Pacific Northwest National Laboratory |
| PRMS | Petroleum Resources Management System |
| PTU | Point Thomson Unit |
| RCOP | Replacement Cost Operating Profit |
| RIK | Royalty in Kind |
| RIV | Royalty in Value |
| SB | Senate Bill |
| S_{hi} | Initial Hydrate Saturation |
| SPE | Society of Petroleum Engineers |
| SPEE | Society of Petroleum Evaluation Engineers |
| TAG | Tax as Gas |
| TAPS | Trans Alaska Pipeline System |
| TCF | Trillion standard cubic feet |

| | |
|------|---------------------------------|
| TVD | True Vertical Depth |
| UOP | Units of Production |
| USGS | United States Geological Survey |
| WPC | World Petroleum Council |